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A PHI Company

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DELAWARE P.S.C.

December 1, 2014

VIA OVERNIGHT DELIVERY
Alisa Bentley, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, DE 19904

Re: Delmarva Power & Light Company
December 1, 2014 Integrated Resource Plan
Filed Pursuant to 26 *Del. C.* §1007(c)(1)

Dear Secretary Bentley:

Enclosed for filing with the Commission are eleven (11) copies of the PUBLIC version of the 2014 Integrated Resource Plan (IRP), with Appendix, of Delmarva Power & Light Company (Delmarva). A Confidential/Sealed version is being filed simultaneously herewith under separate cover.

Should have any questions or require any additional information, please do not hesitate to contact me.

Very ~~truly~~ yours,

Pamela J. Scott

cc: Michael L. Morton (2 copies of Confidential IRP)
Ann S. Visalli (2 copies of Confidential IRP)
David Smalls (2 copies of Confidential IRP)

Delmarva Power & Light Company

2014 Integrated Resource Plan

Filed: December 1, 2014

2014 Delmarva Power

Integrated Resource Plan

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* **Confidential information omitted in these Sections. This information will become public after the completion of the SOS auction process in the Spring of 2015.**

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* **Confidential information omitted in these Sections. This information will become public after the completion of the SOS auction process in the Spring of 2015.**

Section I. IRP Executive Summary

Delmarva Power & Light Company ("Delmarva Power or Company") prepares and submits an Integrated Resource Plan ("IRP") every two years as required by Delaware law[1] and in compliance with regulations adopted by the Delaware Public Service Commission ("Commission").[2] As this IRP was being prepared during the latter half of 2014, several events occurred that have the potential to significantly impact the results of the IRP. These events include: (1) the passage of Senate Bill No. 150 which, among other things, revised and expanded the process for developing and implementing energy efficiency programs in Delaware; (2) a proposed rulemaking by the U.S. Environmental Protection Agency ("EPA") under the Clean Air Act (Sec 111(d)) to regulate greenhouse gas emissions from existing generation plants; and (3) proposed changes by PJM to its' reliability pricing model. While each of these events has the potential to impact electricity prices in Delaware, at the time of the submission of this IRP, specific rules, procedures, and implementation timelines pertaining to these events have not been established. Consequently, an analysis of the potential impact of these events is not provided within the 2014 IRP.

A. Summary of Integrated Resource Plan Findings

On July 8, 2014, the Commission issued Order No. 8574, in Docket No. 12-544, which ratified the IRP submitted by Delmarva on December 6, 2012. As discussed further herein, the 2014 IRP incorporates certain changes noted by the Commission in Order No. 8574, as well as other changes suggested by the parties to that docket through their comments submitted in response to the 2012 IRP. As with the 2012 IRP, the drafting of the 2014 IRP has greatly benefitted from the input received through the collaborative IRP Working Group process.

Retail energy supply rates for Delmarva Power's Standard Offer Service (SOS) customers include the cost of electricity, capacity and ancillary services. Retail supply rates have been stable and mostly decreasing since 2010. Since 2010, while residential SOS customer energy supply rates for the summer period fell from 11.19 cents/kwh to 8.29 cents/kwh in 2013, then rose to 8.71 cents/kwh in 2014, as demonstrated in the chart below:

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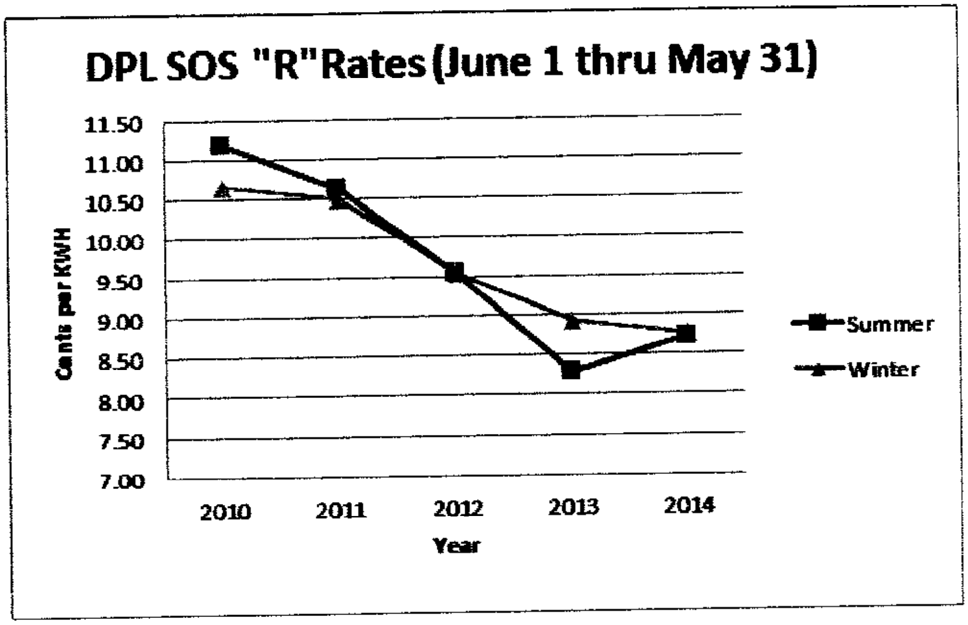
[1] 26 *Del. C.* §1007(c)(1).

[2] 26 *Del. Admin. C.* 3010.



It is expected that the combination of available generation resources and transmission import capability into the PJM DPL Zone under PJM base case assumptions will be sufficient to meet PJM reliability requirements through 2024. This result is made more certain by the implementation of demand response programs designed to reduce customer demand during peak load periods. The Commission approved a Dynamic Pricing Program and a Residential Direct Load Control Program that support this planning objective, and these Programs have proven to be effective since their inception.[3]

Air emissions from power plants in Delaware are expected to decrease over the period 2015-2024.[4] These emissions include carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxide (NO_x). The emission reductions are attributable to a number of factors including: new regulations controlling air emissions from coal fired power plants, the increased use of natural gas fired power generation, energy efficiency, and the increased penetration of renewable generation resources.

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[3] See Commission Order Nos. 8105 and 8253 respectively

[4] It should be noted that the 2014 IRP does not include any impacts associated with the EPA's proposed Rule111(d) of the Clean Air Act. If enacted, Rule 111(d) would require that the states reduce CO2 emissions for existing power plants, potentially having a significant impact on power plant generation in both PJM and Delaware.

Delmarva Power has continued to manage a diverse portfolio of renewable resources in order to comply with the State's Renewable Energy Portfolio Standards Act ("REPSA").[5] The projected impact on average SOS customers' bills to meet the REPSA standards ranges from $8.27/month in 2015 to $13.38/month in 2024. Renewable generation, however, avoids the creation of emissions of CO_2, SO_2, and NO_x, and the estimated health benefits of these avoided emissions may be included in the evaluation of the cost of compliance with RESPA.[6]

B. Background

The 2014 IRP describes the Company's plan to procure the electrical energy requirements for its SOS customers for the 10 year planning period, 2015 – 2024 (IRP Planning Period). This IRP is filed pursuant to Title 26, Section 1007 (c) (1) of the Delaware Code, which provides, in part:

> [Delmarva] is required to conduct integrated resource planning..... In its IRP, [Delmarva] shall systematically evaluate all available supply options during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost. The IRP shall set forth [Delmarva's] supply and demand forecast for the next 10-year period, and shall set forth the resource mix with which [Delmarva] proposes to meet its supply obligations for that 10-year period....

The statutory provisions make clear that while the IRP must investigate all potential opportunities for a diverse and reliable electric supply, including those that would create environmental benefits for Delaware, it must do so with a careful eye on costs. Delaware law specifically provides that in developing the IRP, Delmarva Power must seek to meet its customers' energy supply needs "at the lowest reasonable cost"[7] and "at a minimal cost."[8] As such, the principal objectives of the IRP are to secure for SOS customers a reliable energy supply at a reasonable cost, maintain price stability and, at the same time, provide environmental benefits

[5] 26 *Del. C.* § 351, et. seq.
[6]The Delaware Department of Natural Resources and Environmental Control (DNREC) is currently in the process of finalizing rules for calculating the cost of renewable energy and may include the benefits of avoided air emissions in the evaluation.
[7] 26 *Del.C.*§1007(c)(1)(b).
[8] 26 *Del.C.*§1007(c)(1).

consistent with reasonable cost and price stability.

C. Delmarva Power

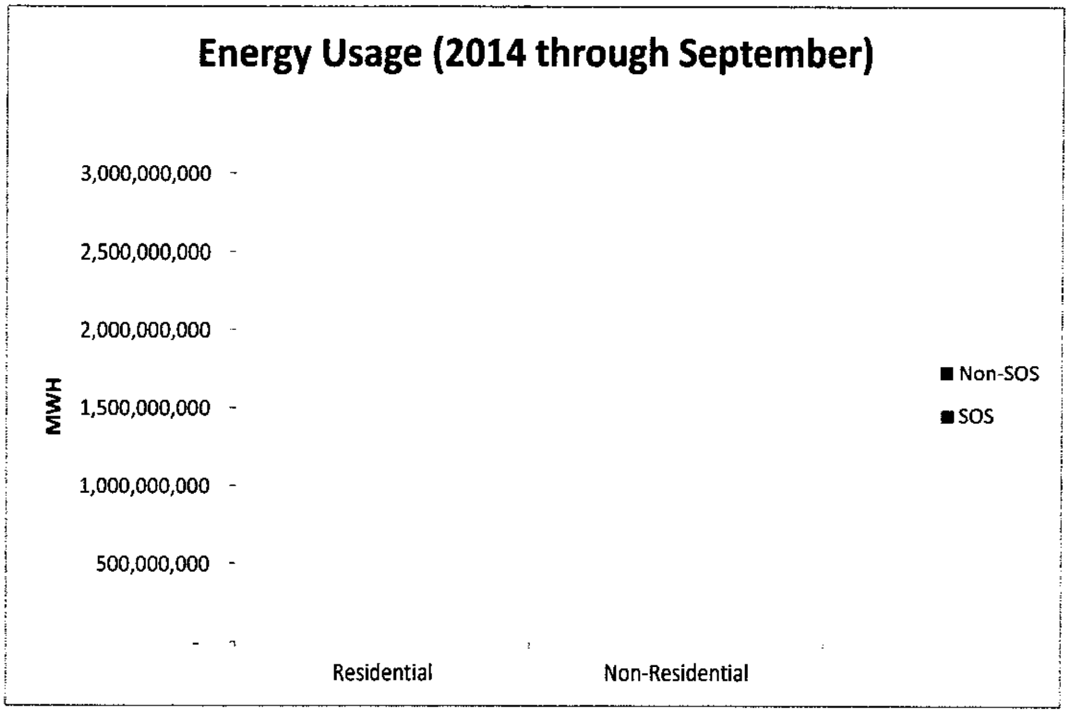
Delmarva Power is a regulated public utility company serving electric and gas customers in Delaware and portions of Maryland. In Delaware, the Company serves almost 307,000 electric energy customers, of which about 267,000 are residential customers. Delmarva Power also serves over 123,750 natural gas customers all of whom reside in New Castle County; however, the IRP focuses only on impacts to electric customers.

Delmarva Power is an electric delivery company, focusing on the transmission and distribution of electricity to its customers. The Company does not generate any electricity or own any generation plants. Delmarva Power's Delaware operations are managed out of four in-state offices, one each in the City of Wilmington, New Castle County, the City of Millsboro and the City of Harrington. Among the Company's assets in Delaware are almost 880 miles of high voltage (69kV and higher) transmission lines, and 73 distribution and transmission substations.

Under Delaware's electricity deregulation laws, Delaware customers can choose their own electric energy supplier. Those customers who do not choose an alternate, competitive supplier are supplied by Delmarva Powerthrough its Standard Offer Supply ("SOS") offering. As of September 28, 2014, about 89% of residential customers' electric usage was provided under the SOS offering, and about 82% of non-residential usage is provided by competitive suppliers. The 2014 IRP is focused on the procurement of the energy supply requirements of SOS customers.

The breakdown of energy usage by residential and non-residential customers for both SOS and non- SOS service for 2014, through September, is shown in the following chart:

Figure 1 – Energy Usage (2014 through September)



D. Load Forecast

Tables 1 and 2 summarize the baseline load forecast for the IRP Planning Period:

Table 1 – Delmarva Total Baseline Forecast

Peak Demand (mW) and Energy Throughput (mWh)

	2015 Delmarva Delaware		2020 Delmarva Delaware		2024 Delmarva Delaware	
	mW	mWh	mW	mWh	mW	mWh
Residential	1,005	3,028,874	1,092	3,033,422	1,139	3,036,402
Small Commercial	34	180,443	36	180,317	38	181,768
Large Commercial & Light Industrial	919	4,942,728	999	4,939,270	1,042	4,979,006
Street Lights	0	37,095	0	37,230	0	37,263
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 2 – Delmarva SOS Baseline Forecast

Peak Demand (mW) and Energy Throughput (mWh)

	2015 Delmarva Delaware SOS		2020 Delmarva Delaware SOS		2024 Delmarva Delaware SOS	
	mW	**mWh**	**mW**	**mWh**	**mW**	**mWh**
Residential	905	2,729,123	984	2,733,221	1,027	2,735,906
Small Commercial	25	136,619	28	136,523	29	137,621
Large Commercial & Light Industrial	142	761,852	154	761,319	161	767,444
Street Lights	0	26,534	0	26,632	0	26,655
[redacted]						

The Load Forecast is described in more detail in Section 4 of the IRP. Appendix 4 provides more detailed documentation of the forecast preparation.

E. Price and Price Stability

Over the IRP Planning Period, more natural gas generation within PJM is expected to come on-line than any other type of generation. Consequently, for this and other reasons, electricity supply prices within PJM are becoming increasingly sensitive to natural gas prices. To evaluate this sensitivity, the IRP Reference Case, which forecasts higher natural gas prices for the region over the planning horizon, was compared with a Low Gas Price Case, which forecasts gas prices similar to current gas prices. Table 3 below shows the projected supply cost for energy, capacity and ancillary services for the IRP Reference Case for SOS Residential and Small Commercial (RSCI) and SOS Large Commercial ("LC") customers compared to the Low Gas Price Case for the IRP Planning Period.

Table 3
Expected SOS Supply Costs RSCI and LC Customers
(Confidential Material Omitted)

Planning Year	Case	RSCI $/MWh	LC $/MWh
2015/2016	Reference Case		
	Low Gas Case		
2016/2017	Reference Case		
	Low Gas Case		
2017/2018	Reference Case		
	Low Gas Case		
2018/2019	Reference Case	$85.70	$74.82
	Low Gas Case	$72.62	$64.41
2019/2020	Reference Case	$93.41	$80.98
	Low Gas Case	$81.65	$71.07
2020/2021	Reference Case	$99.16	$87.29
	Low Gas Case	$85.96	$75.64
2021/2022	Reference Case	$100.55	$88.84
	Low Gas Case	$87.51	$77.22
2022/2023	Reference Case	$106.57	$92.98
	Low Gas Case	$93.33	$81.16
2023/2024	Reference Case	$106.59	$93.16
	Low Gas Case	$93.73	$81.87
2024/2025	Reference Case	$104.82	$92.85
	Low Gas Case	$92.02	$81.23

Table 3 above indicates that energy supply costs for RSCI SOS customers under the IRP Reference Case are expected to rise to $104.82/mWh by 2024/2025. For LC SOS customers, the corresponding supply price under the IRP Reference Case is $92.85/mWh in 2024/2025.

Table 4 below shows the percentage drop in energy supply costs between the IRP Reference Case and the Low Gas Case for RSCI and LC SOS customers.

Table 4 Percentage Change in SOS Supply Costs Low Gas Case vs. Reference Case		
Planning Year	**RSCI**	**LC**
2015/16	-0.04%	-0.15%
2016/17	-2.52%	-4.20%
2017/18	-7.29%	-8.02%
2018/19	-15.27%	-13.91%
2019/20	-12.59%	-12.23%
2020/21	-13.31%	-13.34%
2021/22	-12.97%	-13.08%
2022/23	-12.43%	-12.71%
2023/24	-12.06%	-12.12%
2024/25	-12.21%	-12.52%

Table 5 below presents a projection of the retail customer energy supply tariff rates which include the cost of energy, capacity, ancillary services and other adjustments for residential customers served under the "R" tariff and commercial customers served under the "MGS-S" tariff for the period 2015 through 2020. The projections are based on the IRP Reference Case.

Planning Year	Residential Rates (Tariff "R")				MGS-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2015/16	-	-						
2016/17	-	-						
2017/18	-	-						
2018/19	-	-	8.80	8..59	12.9	7.4	4.22	4.79
2019/20	-	-	9.72	9.21	13.6	8.1	4.45	5.24

F. Environmental

As part of the IRP, Delmarva Power prepared an analysis of the expected power plant emissions occurring over time for the IRP Reference Case. The following charts (Figures 2 through 4) depict the emission levels of carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrous oxide (NO_X) expected to be created from power plants in Delaware for the PJM planning years 2015 – 2024. It should be noted that the projections of the level of air emissions depicted in Figures 2-4 do not assume enactment of the EPA proposed Rule 111(d) affecting CO_2 emissions for existing power plants.

Figure 2

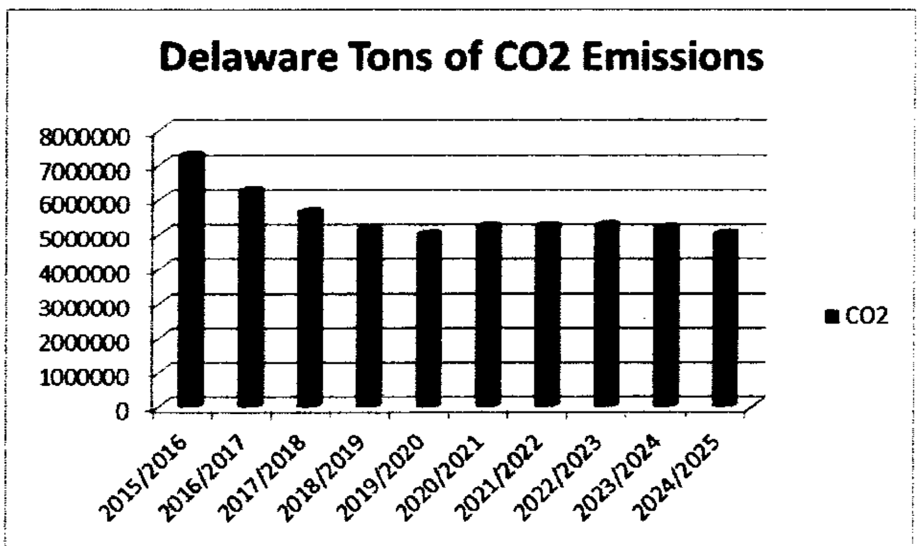


Figure 3

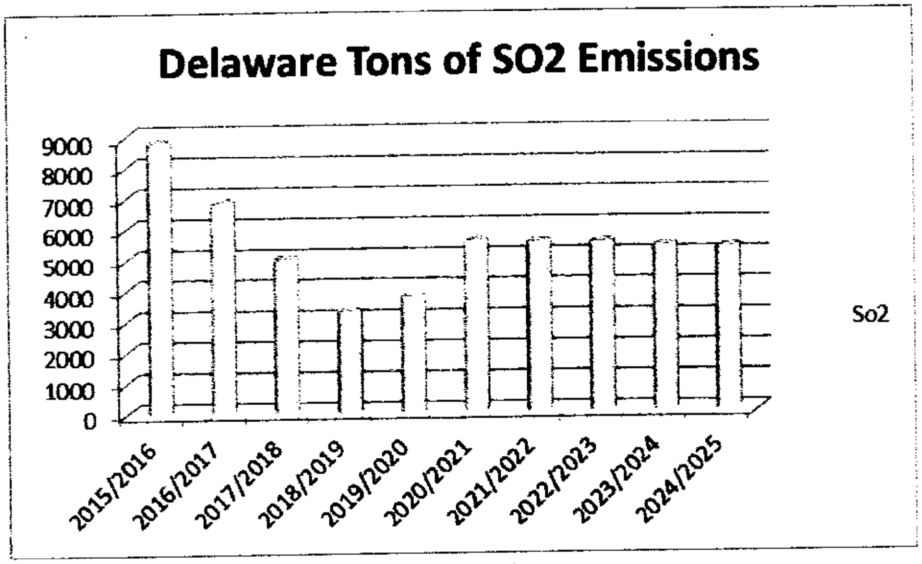
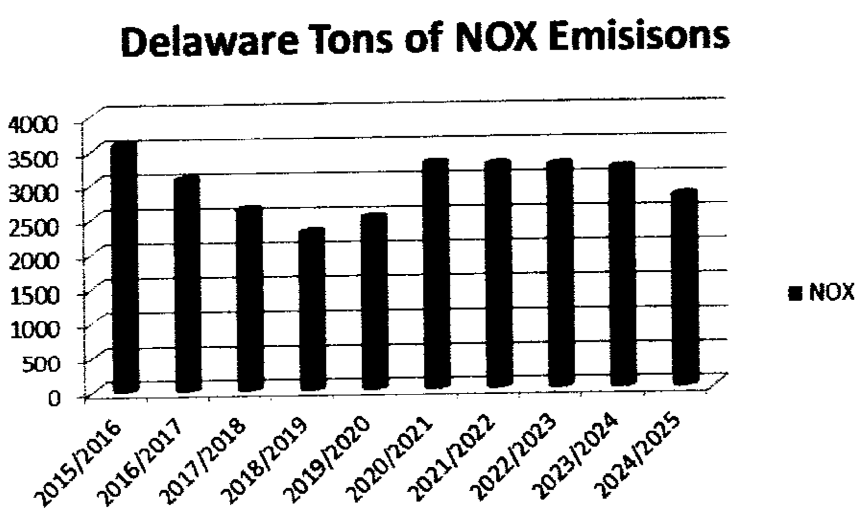


Figure 4



These charts (Figures 2 – 4 above) indicate that under the IRP Reference Case, emissions of CO_2, SO_2 and NO_X are generally expected to decline in Delaware during the ten-year planning period. Although these projections do not include any impact of future enactment of proposed ERA Rule 111(d), the projections do reflect other tightening federal and regional clean air standards, generation retirements and additions, as well as actions that Delaware has taken to increase renewable generation, reduce electric energy consumption and demand, and provide better emission controls for electric generation from coal resources.

The regulations governing the preparation of the IRP require that the Company include an evaluation of and give consideration to environmental benefits and externalities associated with specific methods of energy production.[9] Using environmental modeling tools developed by the EPA and available in the public domain, the 2012 IRP provided an analysis of impacts for the Delmarva Reference Case comparing changes in air quality between 2013 and 2022. Based on these EPA models, the 2012 IRP estimated that the monetized benefit to human health of reducing a ton of SO2 emissions is within the range of \$43,000 – \$110,000, and within the range of \$9,500 – \$25,000 for reducing a ton of NO_x. The monetized benefit for reducing a ton of CO_2 ranges from \$1 to \$100 per ton. These figures could be used to estimate the value of air emission reductions displaced by renewable resources.

G. Renewable Energy

In order to comply with the Delaware Renewable Energy Portfolio Standards (RPS),[10] Delmarva Power manages a portfolio of renewable resources that are supplemented with Renewable Energy Credit ("REC") and Solar Renewable Energy Credit ("SREC") offsets from the Qualified Fuel Cell Provider ("QFCP"), as well as spot market purchases. Renewable energy resources in Delmarva Power's renewable portfolio include:

1. Contracts for the RECs and mWh output of the AES Armenia Mountain, Gestamp Roth Rock, and Gamesa Chestnut Flats wind farms totaling about 125 mW;
2. A contract to purchase 70% of the SRECs from the 10 mW Dover Sun Park; and
3. Over 20 mW of SRECs purchased from the Delaware Sustainable Energy Utility (SEU) through the SREC Procurement Pilot Program, the 2013 SREC Procurement Program, the 2014 SREC Procurement Program, and from a contract with Washington Gas Energy Services.

Securing the RECs, SRECs, and QFCP offsets needed to comply with State requirements is forecast to increase a typical 1,000 kWh residential monthly bill by

[9] 26 *Del. Admin. C.* 3010, §6.1.4.
[10] 26 *Del. C.* §351, et. seq.

$8.27 in compliance year 2015 (June 1, 2015 - May 31, 2016). The impact of RPS compliance on a typical residential customer bill is expected to increase to $13.38 per month in compliance year 2024. DNREC is currently finalizing rules for calculating the cost of compliance with State renewable energy requirements. These rules may include provisions for evaluating the costs that are avoided by using renewable energy resources (such as external health costs).

H. IRP Planning Objectives and Action Plans

Delmarva Power has six planning objectives in preparing this IRP as follows:

1. Reasonable cost and price stability;
2. Meet or exceed reliability standards;
3. Obtaining renewable energy through a diverse portfolio at reasonable costs;
4. Implementing cost effective Demand Response Programs;
5. Meeting energy efficiency goals; and
6. Implementing utility sponsored energy efficiency programs.

For each of these six objectives, the following tables include objective measures, progress made towards meeting the objectives since the 2012 IRP was filed, and action plans for the future.

Planning Objective	Objective Description	Measures	Progress Since 2012 IRP	Action Plan
I. Reasonable Cost and Price Stability	a) Delmarva Power will evaluate generation, transmission and demand side resource options during the IRP Planning Period to ensure that sufficient and reliable resources are acquired at a reasonable cost to meet customer needs. b) Delmarva Power will seek to provide year over year price stability in the prices paid by SOS customers for their total electricity supply.	a) Obtain Commission concurrence that the IRP does not appear unreasonable in meeting these objectives. b) Provide the Commission with information showing changes in rates and procurement cost adjustments.	The Commission issued Order No. 8574 in July 2014 which ratified the 2012 IRP. Delmarva Power has continued to procure Full Requirements Service (FRS) for its SOS customers through the Commission approved reverse auction process. Delmarva Power's strategy is to procure approximately one third of the expected SOS requirements for a three year contract term on an annual basis. The year over year results for Residential and Small Commercial SOS customers since the 2012 IRP are: <u>2013 over 2012:</u> Summer: -13.2% Winter: -6.5% <u>2014 over 2103:</u> Summer: 5.1% Winter: -1.9%	The following actions are expected to occur in the next five years: a) In accordance with Electric Utility Retail Customer Supply Act, the Company will prepare and file an IRP every two years. The IRP will include a systematic evaluation of generation, transmission, and demand side resource options. Under this schedule, Delmarva Power will file the next IRP on or before December 1, 2016. b) The IRP will provide an evaluation of the planning Reference Case showing both the expected outcome in terms of average price and potential ranges of outcomes around the expected price.

Planning Objective	Objective Description	Measures	Progress Since 2012 IRP	Action Plan
II. Reliability	Ensure that the electric system serving Delmarva Power's customers meets all NERC, RFC, PJM, PHI and Delaware transmission electrical reliability requirements.	a. Complete PJM approved zonal RTEP projects on schedule as listed on the "RTEP Construction Status" page on the PJM Website (www.pjm.com). b. Meet or exceed reliability standards in DE PSC Docket 50 "Electric Service Reliability and Quality Standards." From Section 4 of that document, transmission "Reliability and Quality Performance Benchmarks" include: i. Transmission CAIDI & SAIDI (excluding major events) as part of the overall system CAIDI and SAIDI; and, ii. Constrained hours of operation.	A number of major transmission system upgrades, including PJM approved zonal RTEP projects, have been completed by Delmarva Power since the 2012 IRP was filed. Among other projects, this includes the construction of the Indian River-Bishop 138KV line, the install of 75 MVAR SVC at 138th St 138 kV bus and the rebuild of the entire Glasgow to Mt. Pleasant 138 kV line. A complete listing of all transmission projects completed by Delmarva Power since December 2012 is provided in the 2014 IRP. In April 2014, as part of PSC Docket 50, Delmarva Power provided project updates to the Commission as part of the annual "Reliability Performance Report" which showed that Delmarva Power met the standards established by the Commission.	The following are expected to occur annually for the next five years: a) Complete all approved PJM RTEP Delmarva Zone projects by required in-service dates. b) Provide updates for annual Docket 50 transmission standards targets (in "Reliability Planning and Studies Report" - submitted annually in March for the current calendar year) and performance (in "Reliability Performance Report" - submitted annually in April for the previous calendar year).

Planning Objective	Objective Description	Measures	Progress Since 2012 IRP	Action Plan
III. Renewable Energy	a) Obtain renewable energy through a diverse portfolio of renewable energy resources at reasonable cost. b) Prepare a plan to obtain Renewable Energy Credits (RECs) from resources over the IRP Planning Period sufficient to meet the requirements of the REPSA. c) Prepare a plan to obtain sufficient solar resources to meet the State of Delaware's RPS requirements for solar photovoltaic resources. d) Avoid alternative compliance payments under the State RPS. e) Consistent with regulations being finalized by DNREC, provide cost of RPS compliance information as needed.	a) Meet the annual RPS requirements for customers through a portfolio of contracted wind and solar resources, offsets from Qualified Fuel Cell Providers, SRECs purchased from the SEU, and balanced with purchases from competitive short-term markets. b) Minimize alternate compliance payment requirements. c) As may be required by forthcoming regulation, provide information needed to determine the cost of RPS compliance. d.) Submit certified annual RPS Compliance Report with the Commission for each planning year.	The 2013 DE SREC Procurement Program secured SRECs from 385 projects that represent 5.5 MW of solar facilities. Filed the June 2012- May 2013 RPS Compliance Report with the Public Service Commission in September 2013. No alternate compliance payments were made. The 2014 DE SREC Procurement Program secured SRECs from 295 projects that represent 5.5 MW of solar facilities. Filed the June 2013- May 2014 RPS Compliance Report with the Public Service Commission in September 2014. No alternate compliance payments were made.	The following are expected to take place over the next five years: 1. Continue receiving energy and RECs through approved contracts with wind generators: AES Armenia Mountain Wind Energy , Gestamp Roth Rock Wind Energy and enXco Chestnut Flats Wind Energy. 2. Continue receiving SRECs from the following approved contracts from solar providers: Dover Sun Park, the DE SREC Procurement Pilot Program, the 2013 DE SREC Procurement Program and the 2014 DE SREC Procurement Program. 3. Incorporate REC and SREC offsets derived from the QFCP to help meet the State RPS in the most cost-effective manner.

Planning Objective	Objective Description	Measures	Progress Since 2012 IRP	Action Plan
IV. Demand Response (DR)	Implement Commission approved, utility provided, technically feasible, and cost effective Demand Response Programs with a focus on contributing towards meeting the peak demand reduction goals from the Energy Conservation and Efficiency Act of 2009 of 15% by 2015	Peak demand reduction achievements have been measured each year beginning in 2013. The Energy Wise Rewards program results are filed quarterly with the Delaware Public Service Commission. The Peak Energy Savings Rebate program results are filed annually with the Delaware Public Service Commission.	New demand response programs have been enabled by deploying Advanced Meter Infrastructure (AMI) in Delaware. The Peak Energy Savings Rebate program has been initiated for Delmarva Power's SOS customers. During 2013, this program was operated on two separate dates with an average 46,000 customers participating. The 2013 results of the program have been filed with the Commission, and the 2014 results will be filed by early 2015. Delmarva Power also continues to operate the Energy Wise Rewards Direct Load Control program. There are currently almost 47,000 participating customers in this program. Program results through September 2014 have been filed with the Commission. Future results will be filed quarterly.	**Residential DR Programs** Over the next two years: 1. Continue Peak Energy Savings Rebate and Direct Load Control Program education efforts. 2. Conduct program load reduction events. **Non-Residential DR Programs** 1. Implement non-residential phase-in of Dynamic Pricing for AMI Field Acceptance Test for SOS customers. 2. Prepare and file testimony seeking Commission authorization to establish a non-residential Direct Load Control Program for air conditioning systems. Delmarva Power will monitor and evaluate the impacts of these Programs and request program revisions and improvements as needed over the next 5 years.

Planning Objective	Objective Description	Measures	Progress Since 2012 IRP	Action Plan
V. Energy Efficiency	Collaborate with key stakeholders including DNREC, Commission Staff, the DPA and the SEU as enabled by the 2014 revisions to the Energy Efficiency Act of 2009 to successfully implement cost-effective energy efficiency programs on a timely basis for Delmarva Power customers.	On August 6, 2014 Gov. Markell signed SB150, which, among other things, included revisions to the Energy Efficiency Act of 2009 to allow Delmarva Power to implement cost-effective energy efficiency programs. Prior to implementation, the programs must be recommended by a Task Force and approved by the Public Service Commission. As of the time of the filing of this IRP, the details of the energy efficiency program implementation process including stakeholder participation, program selection and design, measurement and verification, and project scheduling are not known.	The SEU has continued to obtain energy efficiency savings through implementation of the programs under its supervision. The SEU has indicated that it is has been insufficiently funded to meet the goals and targets of the Energy Efficiency Act of 2009 by itself.	Over the next two years Delmarva Power will work collaboratively with the other stakeholders to effectively and timely implement energy efficiency programs consistent with the provisions of SB 150.

Planning Objective	Objective Description	Measures	Progress Since 2012 IRP	Action Plan
VI. Utility Provided Energy Efficiency Programs	Implement utility energy efficiency initiatives such as transmission and distribution system improvements and street lighting upgrades.	These programs/initiatives are implemented as available operational opportunities occur. Transmission and distribution improvements follow the processes and procedures as outlined in the PJM RTEP process, while transformer upgraders occur upon failure of existing equipment.	1. Continued installation of high efficiency transformers and replaced transmission conductors. 2. Continued installation of distribution line capacitors, which resulted in lower losses on the system. 3. Continued replacement of Mercury Vapor (MV) streetlights with High Pressure Sodium (HPS) streetlights.	1. Implement transmission and distribution improvement measures as described in the PJM RTEP. 2. Continue installation of high efficiency transformers. 3. Continue streetlight improvement plan. 4. Work with SEU to determine other program utility implementation opportunities.

I. Recommended Path Forward

Upon receipt of this filing, the Commission will open a docket for the review and evaluation of the 2014 IRP. Because the IRP Working Group has provided an effective way to share information among stakeholders in a collaborative and transparent manner for the last several IRP's, Delmarva Power recommends that the Commission continue to use the IRP Working Group process to review and evaluate the 2014 IRP. Specifically, Delmarva suggests that a Working Group meeting be scheduled with the parties in the docket to discuss the 2014 IRP and allow Delmarva Power to respond to the parties' questions prior to their filing of formal comments in the docket. This will allow for timely and effective sharing of information, allow the Company to provide additional clarification as necessary, and provide greater focus on any areas of concern among the parties that may arise.

As the IRP Working Group process proceeds, Delmarva Power's current renewable portfolio and SOS procurement strategies, which have been developed and refined with Commission approval on an on-going basis, will continue.

Section II. Significant Events since the filing of the 2012 IRP

Pursuant to the Electric Utility Retail Customer Supply Act ("EURCSA") enacted in 2006, Delmarva Power is required to prepare and file an IRP every two years.[11] The IRP is designed to provide a comprehensive review of Delmarva Power's plans to procure energy for SOS customers for a ten year period.[12]

Prior to the 2014 IRP, the most recent IRP prepared by Delmarva Power was filed with the Commission on December 6, 2012 ("2012 IRP"). The 2012 IRP was submitted pursuant to the regulations adopted by the Commission on December 8, 2009, Order No. 7693, in PSC Regulation Docket No. 60.[13] On July 8, 2014, the Commission issued Order No. 8574 in which the 2012 IRP was ratified. A copy of Order No 8574 is provided at Appendix 3.

Following issuance of Order No. 8574, Delmarva Power held a working group meeting with interested parties to discuss the planning and development of the 2014 IRP. The principal topics discussed at the working group meeting included: the method to estimate energy efficiency savings attributable to the programs implemented by the SEU, planned sensitivity analyses, and IRP model assumptions. Those parties participating included Delmarva Power, Commission Staff, DNREC, DPA, the Caesar Rodney Institute ("CRI"), the Mid Atlantic Renewable Energy Coalition ("MAREC"), and the SEU.

One of the challenges of preparing an IRP is to keep the planning assumptions underlying the resource analysis as current and accurate as can be reasonably expected given the time and resource requirements of developing an IRP. Since the filing of the 2012 IRP on December 6, 2012, a number of events have taken place that impact or may impact the preparation and development of the 2014 IRP. The 2014 IRP incorporated these events into the resource planning analysis to the extent such information was available or known before the analysis for the IRP needed to begin in order to meet the December 1, 2014 filing deadline. Brief descriptions of the more important events that have occurred from a resource planning perspective since the 2012 IRP was filed and ratified are described below.

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[11] .26 *Del C* § 1007 (c)(1).
[12] *Id.*.
[13] 26 *Del. Admin. C.* 2009 and 2010.

Energy Efficiency

As part of the IRP, Delmarva Power must include a detailed description of its energy efficiency activities. Pursuant to 26 Del C § 1500, et seq. Delmarva Power is required to implement electricity demand response programs while demand-side management and other energy efficiency activities are to be implemented by the SEU in collaboration with Delmarva Power. The contributions of these programs are considered in meeting the requirements set forth in the Energy Efficiency Resource Standards Act of 2009 (the "Act") which was enacted by the General Assembly to promote the implementation of cost-effective end-user energy efficiency savings opportunities. The Act establishes energy efficiency goals to be achieved by the utility by 2015.

In August of 2014, Governor Markell, signed Senate Bill 150 ("SB 150") into law which, among other things, made certain changes to the energy efficiency program requirements by stating that each affected energy provider shall implement energy efficiency, energy conservation, and peak demand reduction programs that are cost-effective, reliable and feasible as determined by regulations to be subsequently adopted through DNREC in collaboration with the SEU. To accomplish this, SB 150 establishes an advisory council to be headed by the Secretary of DNREC. The advisory council is charged with assisting affected energy providers in the development of energy efficiency, peak demand reduction and emission-reducing fuel switching programs, in collaboration with Commission Staff and the DPA, and to establish methods to evaluate, measure, and verify the energy savings resulting therefrom. Based on the recommendations of the advisory council, Delmarva Power would submit three year program implementation plans to the Commission for approval. If the Commission approves the programs, Delmarva Power could proceed with implementation. It is anticipated that this process, by broadening Delmarva Power's ability to participate alongside the SEU in pursuing energy efficiency, will greatly expand the effective delivery of energy efficiency savings programs to Delmarva's customers. However, as the legislation has just been signed, it will take some time for the advisory committee to organize and begin its work and for Delmarva Power to prepare implementation plans based upon the advisory committee's recommendations. Consequently, for the purposes of the 2014 IRP, the Company has not included the potential energy savings that may occur as a result of the passage of SB150. It is anticipated that the next IRP, expected to be filed December 1, 2016, would include these savings estimates, as available.

Programs to Procure Solar Renewable Energy Credits

On January 22, 2013, the Commission approved Delmarva Power's proposed 2013 Program for the Procurement of Solar Renewable Energy Credits (the "2013 SREC Program"). The 2013 Program was based on the requirements of REPSA,[14] the recommendation of the Renewable Energy Task Force (which is charged with making such recommendation to the Commission), and the Pilot Program for the Procurement of Solar Renewable Energy Credits which had been

[14] 26 *Del. C.* §351, et. seq.

previously approved by the Commission.[15] Pursuant to the 2013 SREC Program, the SEU conducted a competitive auction to secure 20 year contracts for SRECs from private solar developers. SRECs secured through contracts accepted by the SEU and approved by the Commission were transferred to Delmarva Power. Under the 2013 SREC Program (and unlike the Pilot Program), smaller solar systems less than 250 kW in size were provided an administratively set price. The 2013 SREC Program resulted in awards for 385 projects for the SRECs produced by 5.5 mW of new solar systems.

On April 15, 2014, the Commission approved Delmarva's proposed 2014 Program for the Procurement of Solar Renewable Energy Credits (the "2014 SREC Program").[16] The 2014 SREC Program is similar to the 2013 SREC Program except for some changes in contract terms. The 2014 SREC Program resulted in awards for 295 projects for the SRECs produced by an additional 5.5 kW of new solar systems.

Delaware Qualified Fuel Cell Provider

In July 2011, the Governor of the State of Delaware signed legislation that establishes that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider" or "QFCP") is an eligible resource for RECs under REPSA. The legislation also provides for a reduction in Delmarva Power's REC and solar REC requirements based upon the actual energy output of a QFCP.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as a qualified fuel cell provider. Bloom Energy has constructed a fuel cell facility at two locations in Delaware. The first site, a 3 mW fuel cell facility at Brookside, went into commercial operation on June 18, 2012. The second site, a 27 mW fuel cell facility located near Red Lion, was phased into commercial operation over twelve months beginning in December 2012. The entire 27 mWs at the Red Lion Site became commercially available on November 13, 2013. In 2013, the fuel cells at the two sites achieved an average availability factor of 83%.

New Combined Cycle Natural Gas Generation

Since the 2012 IRP was filed, the Calpine Corporation ("Calpine") has begun construction of a 309 Mw combined cycle gas-fired generation plant in Dover, Delaware. The facility, referred to as the Garrison Energy Center, has cleared the relevant PJM RPM capacity auctions and is expected to begin commercial operation by June 15, 2015. Consequently, the Garrison Energy Center is included as a resource in the 2014 IRP beginning in 2015. The Garrison Energy Center is being constructed as a merchant facility without a long term power purchase agreement.

[15] See PSC Order No. 8075 in Docket No. 11-399.
[16] See PSC Order No. 8551 in Docket No. 14-41.

EPA Proposed Rule 111(d): Emission Guidelines for Existing Stationary Sources, EGU's

On June 2, 2014, EPA released proposed rules regarding the emissions of CO2 from existing Electric Generating Units ("EGU's"). The proposed rules are entitled "Emission Guidelines for Existing Stationary Sources, EGU's" and were issued under Sec 111(d) of the Clean Air Act. In the rule, EPA proposes enforceable state-by-state CO2 performance goals. The goals are not directly based on the performance of fossil fuel generating plants, but rather, on a multi-factor approach of carbon reductions based on 4 building blocks of carbon reduction strategies.

The building blocks include:

1. Heat Rate improvements at existing power plants;
2. Increased utilization of existing natural gas combined cycle plants;
3. Increased use of zero emitting generation and renewables; and
4. Increased demand side energy efficiency.

Although each state, including Delaware, has been assigned interim and final CO2 reduction goals, EPA has given a fair amount of latitude within the proposed rules on how the individual states can design and implement the state specific CO2 reduction plans using the 4 building blocks, including the option of participating in multi-state plans. If proposed Rule 111(d) is enacted on the current schedule, State specific plans would need to be submitted to EPA in 2016, although extensions are available. As a result of implementation of this rule, EPA predicts a 25% reduction in CO2 emissions by 2025, and a 30% reduction by 2030.

Because the planning horizon of Delmarva Power's IRP extends for 10 years, enactment of proposed Rule 111(d) could have a significant impact on the IRP not only because of possible subsequent actions taken by the State of Delaware but also due to the responsive actions taken by other states in the region. However, as of December 1, 2014, Rule 111(d) has not yet been finalized or enacted, nor is it clear at this point how each of the states in the region would choose to comply. Therefore, for the purposes of the 2014 IRP, the impact of proposed Rule 111(d) has not been included in the analysis. If Rule 111(d) is enacted and the Delaware compliance strategy becomes known, such analyses could be included in future IRPs, as appropriate.

EPA MATS Rule

The final EPA Mercury and Toxic Standards ("MATS") rule for existing fossil fuel fired power plants was finalized in December 2011 and published in the February 16, 2012 Federal Register. It is set to take effect in April 2015. The MATS rule includes numerical emission limits for mercury, Particulate Matter ("PM") (as a surrogate for toxic, non-mercury metals) and Hydrogen Chloride for all existing and new coal-fired EGUs. Existing and new oil fired EGUs are also subject to emission limits for mercury, PM, Hydrogen Chloride as well as Hydrogen Fluoride.

Since being finalized, the MATS rule has been challenged in court but, to date, the courts have upheld the rule. Within PJM, the implementation of this rule, in combination with low natural gas prices, has been a major factor in the recent and expected retirements of older coal fired generation plants.

PJM Capacity Performance Proposal

PJM, the Regional Transmission Operator ("RTO") coordinates electric markets across the Mid-Atlantic region (including Delaware) and parts of the mid-west. For many years PJM has used the Reliability Pricing Model ("RPM") to conduct an annual auction for electrical capacity. Generation, demand response, and energy efficiency resources have been eligible to participate in the annual capacity auction. A primary purpose of the capacity auction was to cost-effectively ensure that sufficient capacity was available across PJM to reliably serve customer load. However, recent events have caused PJM to propose significant changes to the RPM process. Two of the major events prompting PJM's proposed changes include the polar vortex occurring during the winter of 2013- 2014, and a judicial order vacating FERC Order No 745.

The new RPM auction process envisioned by PJM would create a new "Capacity Performance" product. This new capacity product would provide capacity in the summer, winter, and any extreme weather or system emergency. Penalties for non-performance by generators would be significant. Capacity resources not qualifying or clearing as Capacity Performance resources would be able to participate in RPM as a "Base Capacity" resource. Effective May 15, 2015, PJM proposes to secure 80% of its annual capacity requirements with the Capacity Performance product and the remaining 20% with the Base Capacity product.

The nature and timing of these proposed changes are likely to impact the IRP. At this time, however, given the uncertainty around the proposed changes and the details of their implementation, the 2014 IRP is based upon the existing RPM process and the impact of any changes proposed by PJM have not been evaluated.

Section III. Overview of The IRP Analysis and Modeling Structure

This Section of the IRP describes the overall analytical approach and major modeling tool used in the 2014 IRP analysis. This is followed by several sections describing, in more detail, the key components underlying the 2014 IRP. These sections include; the Load Forecast, Demand Side Management (DSM), Transmission Resources, Supply Side Resources and Environmental Regulations, and Renewable Resources.

The intent of Delmarva Power's 2014 IRP is to provide Delmarva Power's customers and regulators with a road map of how, at the time the IRP is filed, the Company intends to procure electric energy for its SOS Service customers for the next ten years in a way that balances cost, price stability and environmental benefits. Delmarva Power's overall approach to developing the IRP is based upon the following general analytical approach:

1. Begin by preparing a detailed view of the future from 2015 – 2024 for an expected or "Reference" Case. The preparation of the 2014 IRP Reference Case required an intensive modeling effort employing a generation system planning model. The results of the Reference Case provide the data needed to develop an expected view of future prices, price stability, and environmental benefits for Delmarva Power's customers.
2. After completion of the Reference Case, a sensitivity analysis was performed around a low natural gas price scenario to gain a better understanding of the risk associated with the natural gas price assumptions underlying the Reference Case.
3. Provide the Public Service Commission with the results of the IRP analysis in a clear and concise manner for their consideration under the current IRP Docket.

In order to prepare a plan that meets the broad objectives of the IRP, it is necessary to use a comprehensive generation resource planning model. To this end, Delmarva Power retained Siemens Industry Inc., for its Pace Global business ("Pace Global") to prepare an independent PJM market assessment covering the period from 2015 to 2025 ("Study Period") and to provide the detailed resource modelling for the 2014 IRP filing. This section provides an overview of Pace Global's modeling approach which was used to prepare the 2014 IRP Reference Case.

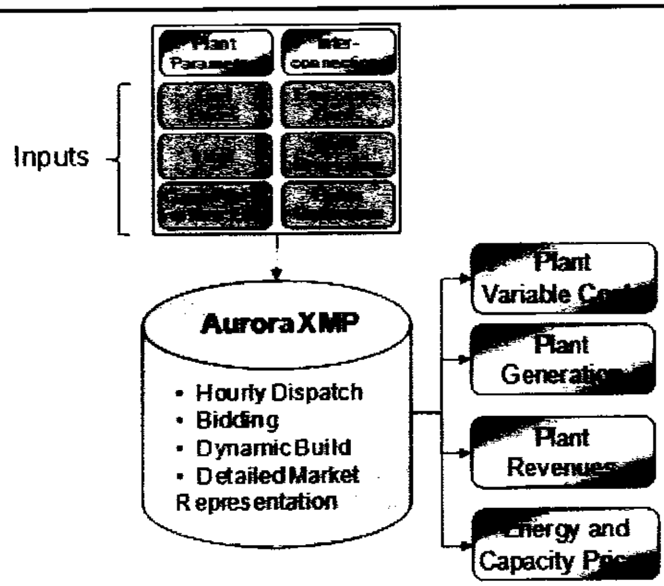
POWER MARKET MODELING

Pace Global deploys an hourly chronological dispatch model to simulate the economic dispatch of power plants within a competitive framework. Representations of hourly regional demand profiles and plant-level supply characteristics are included, as well as detailed assessments on the fundamental drivers of power plant dispatch within each relevant market area. Key components of the methodology include:

- **Load Forecast:** Pace Global independently develops regional load forecasts based on the historic relationship between economic drivers, weather, and load.
- **Regional Fuel/Emission Projections:** Pace Global develops independent projections of fuel and emission pricing inputs based on the fundamental drivers of each market and a comprehensive review of regulatory environments. Itsnatural gas market modeling is performed in the Gas Pipeline Competition Model ("GPCM"), which assesses the fundamental relationships between supply and demand across all sectors.
- **Renewable Generation Profiles:** Pace Global analyzes the historic generation of renewable technologies throughout its modeling regions in order to characterize renewable generation profiles.
- **Bidding Function:** Pace Global's market simulations incorporate bidding behavior and scarcity premiums in its dispatch algorithm. Each region's bidding function is based on hourly analyses of the historic relationship between prices and reserve margins.
- **Dynamic Capacity Expansion:** Gas-fired, wind, and solar capacity expansions are built dynamically when observed margins reach a specified threshold.

A summary of the methodology with key inputs, algorithms, and outputs is shown in Figure 1.

Figure 1:
Pace Global Market Analysis Methodology



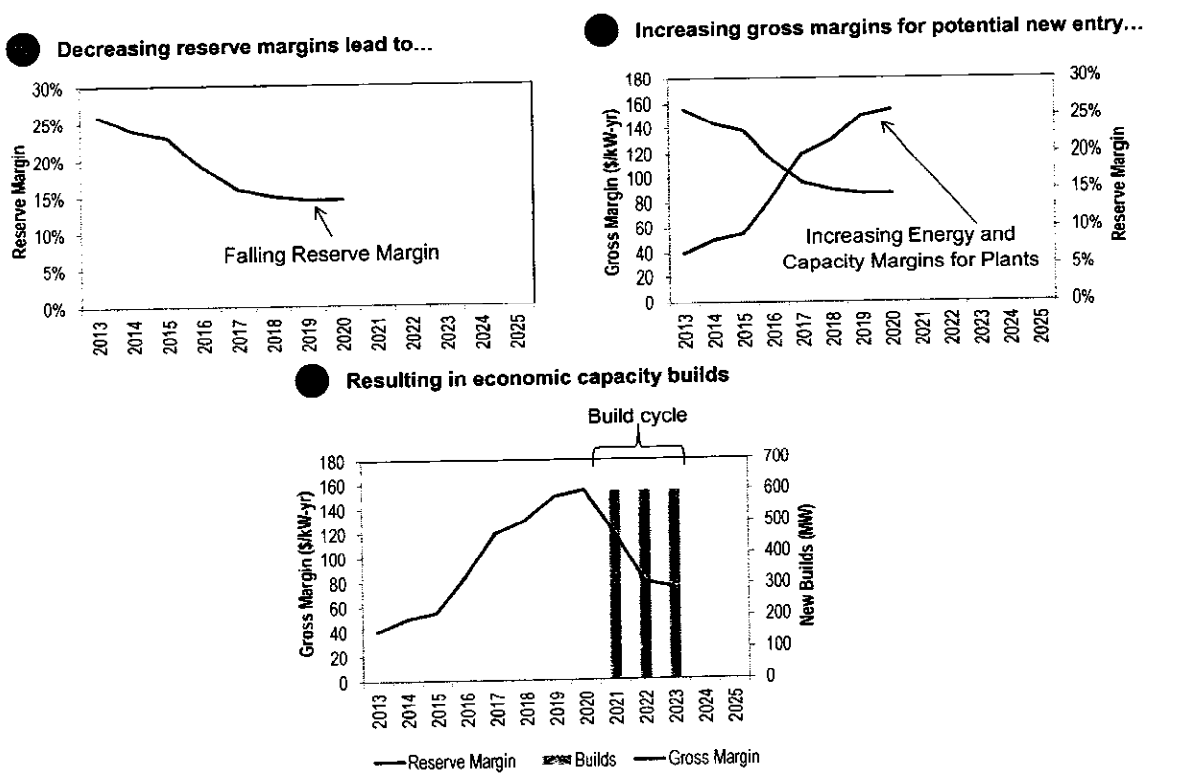
Source: Pace Global

DYNAMIC BUILD CAPACITY EXPANSION

Pace Global incorporates the dynamic simulation of additional economic capacity in our long term analyses. With this approach, incremental expansion is expected when economic conditions provide a sufficient rate of return for new units. Where net energy and capacity revenues together justify the construction of a new unit on the basis of a historic trend, a new unit is built. Sustained positive returns, generally stimulated by falling reserve margins and rising prices are expected to lead to capacity additions. The magnitude of the capacity expansion depends on the achieved Return on Investment ("ROI") specific to the type of generating plant.

Pace Global's dynamic build logic is illustrated in Figure 2. This graphic illustrates how new capacity enters the market according to economic signals. For example, following an expected tightening in system reserve margins over the period 2013-2017, the system is expected to tighten during the 2018-2020 timeframe. In this example, we project that rising margins in the period 2015-2019 will send a signal causing a new plant to come online around the 2021 time frame.

Figure 2: Dynamic Build Simulation Logic



Source: Pace Global

The dynamic expansion methodology is currently applied to incremental natural gas-fired combined cycles, natural gas-fired peaking units, wind, and solar builds in the region. This allows all market simulations to incorporate the reactive behavior observed in the market to periods of sustained margins.

CAPACITY PRICING

Pace Global's capacity price forecast begins with PJM's annual capacity auction, the RPM, which clears capacity prices three "PJM years" (June 1 through May 30 of the following year) in advance. The last auction occurred in May 2014, meaning prices are known and reported "as-cleared" through the first five months of 2018. Beyond the immediate time period, Pace Global models PJM's capacity market under conditions associated with the three major drivers: regional reserve margin, CONE (levelized values across technologies are provided in the following section), and revenue opportunities from energy and ancillary services. As an example, low reserve margins and a high CONE are likely to favor the value of existing capacity, driving the capacity price upwards. High plant energy margins indicate either low fuel costs or high energy prices, and tend to drive the capacity price down.

RENEWABLE ENERGY CREDIT PRICING

REC pricing curves are developed using a bottom-up approach assuming that renewable capacity will be developed if renewable project revenue including power, capacity, and REC value meet investor return requirements. Demand for renewable energy is driven by state RPS requirements that set the parameters for RECs based on existing polices. Due to the significant interstate trading of RECs and the relative continuity of "Tier I" or equivalent requirements in PJM, Tier I/Class I REC prices for these states are modeled as a single region, with demand and supply defined as the aggregate of the region. The REC floor price for both regions is set at a nominal level of a couple of dollars on par with that of the voluntary (Green-e certified) REC market. The ACP for the PJM market is assumed at $50/MWh. Pace Global projects REC value between this defined floor and ceiling by the supply and demand balance differentials between actual supply and demand mandated by the applicable RPS, the more undersupplied the market the higher the REC price drivers. Pace Global calibrates the pricing function based on historic relationship between the relative supply as compared to demand of RPS mandate and demonstrated market pricing.

Although REC pricing varies notably by procurement method and bilateral terms and conditions (i.e. long term vs. spot, bundled vs. unbundled, etc.), it is anticipated that as these markets mature and liquidity and pricing transparency increase that the behavior of market prices will become more highly correlated with actual market supply and demand over the next several years, as the markets emerge out of their infancy.

ESCALATION RATE

Table 1 shows Pace Global's annual deflator series. Pace develops its market projections in real terms and converts prices to nominal values as necessary using the market rate implied by the yield on treasury bonds and similar maturity Treasury Inflation Protected Securities (TIPS). The yield quoted on treasury bonds is equal to the real yield plus inflation, while the yield quoted for TIPS is the real yield. Subtracting the yield of TIPS from the yield of Treasury bonds arrives at the market's forward implied inflation rate. Beyond 2020, Pace uses a general inflation rate of 2.4%.

Table 1: Pace Global's Annual Deflator Series

Year	Deflator Series
2014	1.016
2015	1.033
2016	1.050
2017	1.067
2018	1.086
2019	1.106
2020	1.126
2021	1.149
2022	1.174
2023	1.199
2024	1.226
2025	1.254

Source: Pace Global and U.S. Treasury Department.

Section IV. Load Forecast

Delmarva Power's 2014 ten year energy procurement plan to meet the electrical requirements for SOS customers is based on an internally prepared load forecast covering the planning period 2015 through 2024. Section 4 of the IRP regulations provide detailed requirements for preparing a range of load forecasts as well a review of historical load data. Detailed documentation of the Company's load forecasts and its forecasting methods, intended to meet these requirements, is attached as Appendix 4 to this IRP. Delmarva Power prepares both a "baseline" forecast and a Reference Case forecast for the IRP. The baseline forecast is derived from econometric modeling techniques but does not include the effects of future DSM programs. When the expected impacts of future DSM programs, which are estimated separately from the econometric baseline forecast, are subtracted from the baseline forecast, the result is termed the Reference Case Forecast. The major load forecast results are provided below.

Baseline Forecast

Table 1 summarizes the baseline forecast for summer peak demand (mW) and energy throughput (mWh) for all Delmarva Power customers for 2015 (the initial year of the 2014 IRP Planning Period), 2020 and 2024 (the last year of the 2014 IRP Planning Period). Table 1 below provides this information for Delmarva Power's three major categories of customers (with street lights added as a fourth category for energy throughput). Table 2 below provides similar information for Delmarva Power's SOS customers.

Table 1
Delmarva Power & Light
Baseline Forecast
All Customers

Peak Demand (mW) and Energy Throughput (mWh)

	2015 Delmarva Delaware		2020 Delmarva Delaware		2024 Delmarva Delaware	
	mW	mWh	mW	mWh	mW	mWh
Residential	1,005	3,028,874	1,092	3,033,422	1,139	3,036,402
Small Commercial	34	180,443	36	180,317	38	181,768

Large Commercial & Light Industrial	919	4,942,728	999	4,939,270	1,042	4,979,006
Street Lights	0	37,095	0	37,230	0	37,263
[redacted]						

Table 2 – Delmarva Power & Light
Baseline Forecast
<u>SOS Customers</u>

Peak Demand (MW) and Energy Throughput (MWh)

	2015 Delmarva Delaware SOS		2020 Delmarva Delaware SOS		2024 Delmarva Delaware SOS	
	mW	mWh	mW	mWh	mW	mWh
Residential	905	2,729,123	984	2,733,221	1,027	2,735,906
Small Commercial	25	136,619	28	136,523	29	137,621
Large Commercial & Light Industrial	142	761,852	154	761,319	161	767,444
Street Lights	0	26,534	0	26,632	0	26,655
[redacted]						

Load Growth Cases

In addition to providing a "baseline" forecast, the IRP regulations require Delmarva Power to prepare a range of load growth forecasts for a number of different assumptions. The range of forecasts can be used in the IRP sensitivity analyses. Figures 1-3 below present, for differing assumptions, the Company's forecast for the unrestricted summer peak demand, unrestricted winter peak demand and annual mWh for all Delmarva Power's Delaware customers over the IRP Planning Period.

Figure 1

DPL Delaware Jurisdictional Summer Peak Demand (mW)

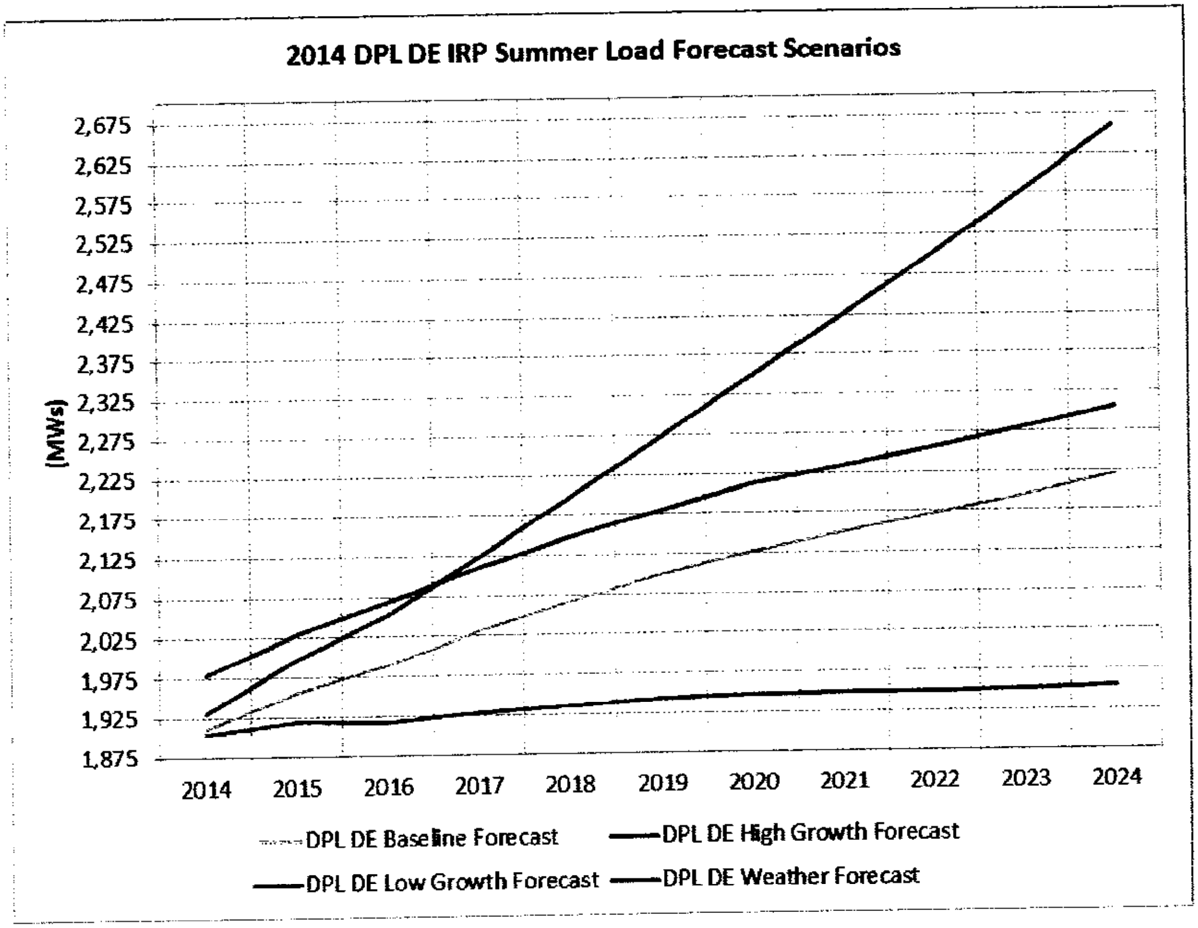


Figure 2

DPL Delaware Jurisdictional Winter Peak Demand (mW)

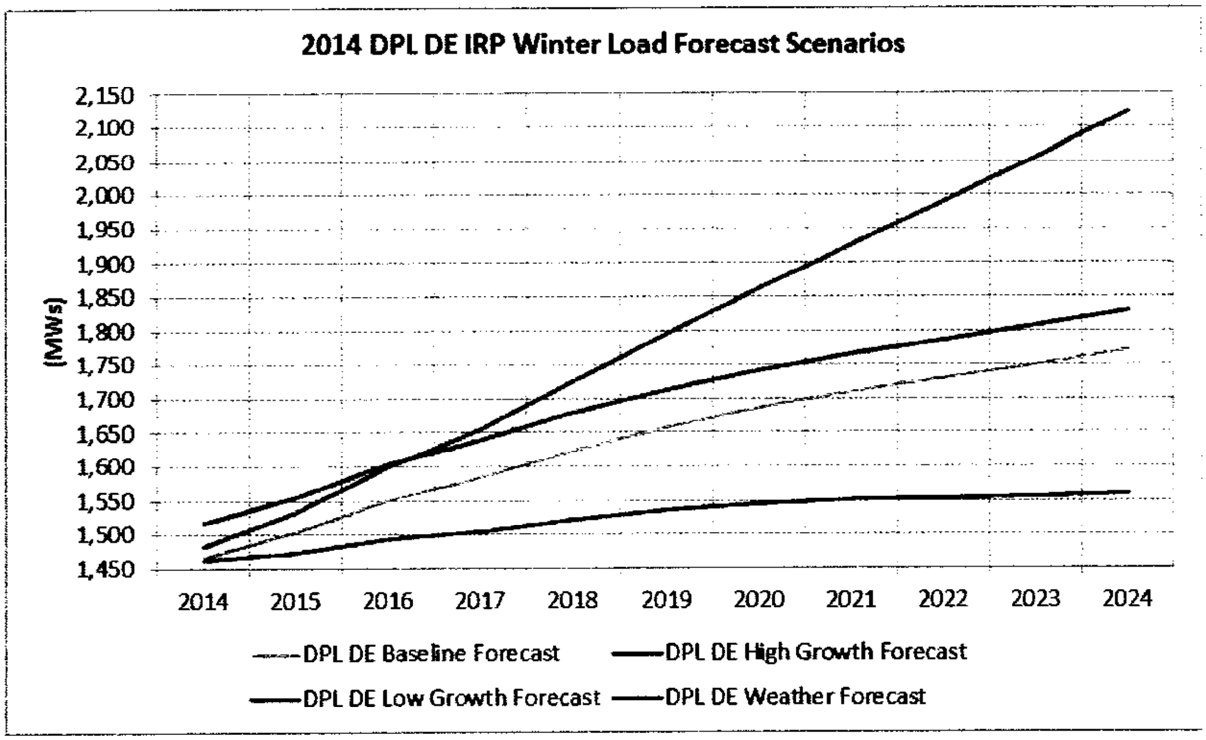
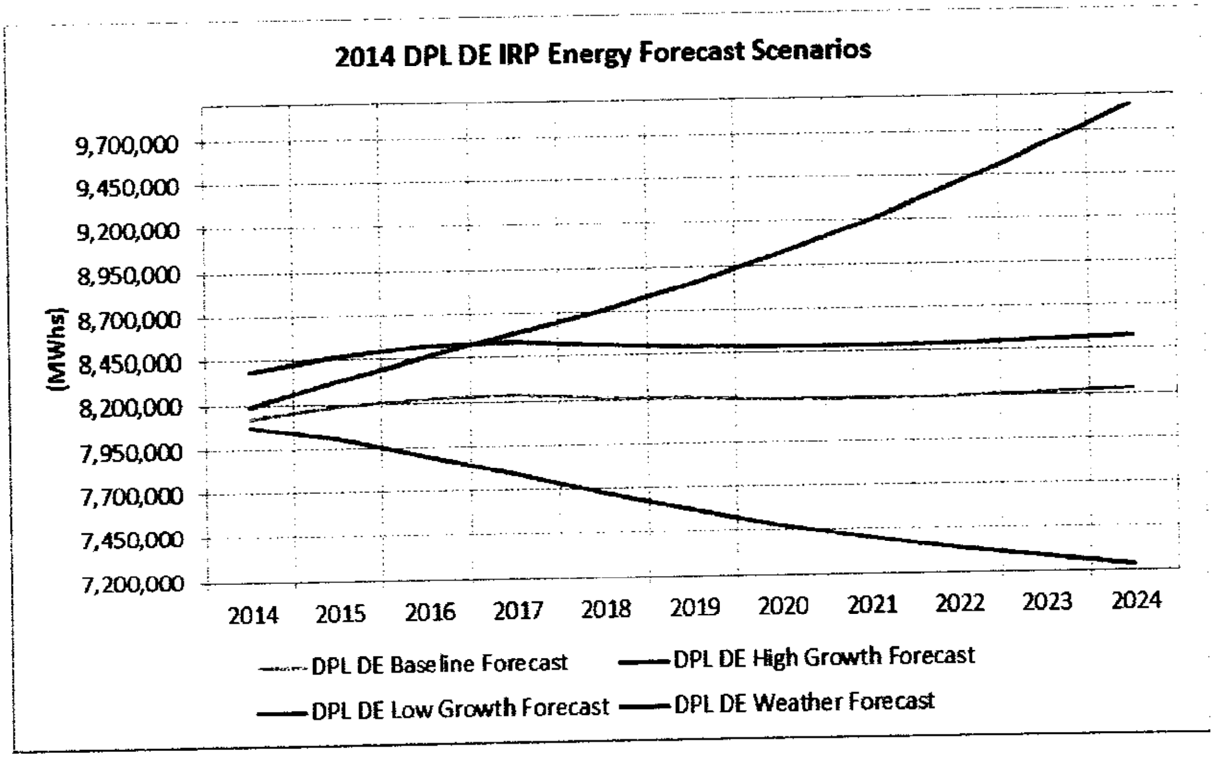


Figure 3

DPL Delaware Jurisdictional Annual Energy (mWh)



In Figures 1-3, the green line represents the Baseline forecast; it is assumed that 50% of the possible future outcomes will be above this forecast and 50% will be below. The red and blue lines represent, respectively, High and Low Economic Growth Scenarios. It is assumed that 10% of the possible outcomes will lie above the High Economic Forecast and 10% will lie below the Low Economic forecast.

Finally, the purple line represents the Extreme Weather Case. This Case is meant to reflect climate change potential for the region. Extreme Weather is represented by calculating the average and standard deviation of heating and cooling degree days for each month of the year. In the Extreme Weather Case, monthly heating and cooling degree days are set equal to their historical average, plus two standard deviations.

IRP Load Forecast Requirements

Appendix 4 includes a discussion of the methodology used in developing these forecasts and provides further information on these forecasts including:

- Historical data and future estimates of:
  - Five year historical loads, current year-end estimate and 10 year weather adjusted forecast.
  - DPL – DE and DPL DE SOS load forecasts aggregated and by customer category, including capacity (mW) and energy (mWh) data.
- Winter and summer peak demand for total DPL DE load and DPL DE SOS load by customer class.
- Weather adjustments including consideration of climate change potential.
- A description of the process used to develop the forecast, probability of occurrence and how well the model predicted past load data for five years.

Reference Case Forecast

As mentioned earlier, the Baseline Forecast described above does not include the effects of future DSM programs. However, for purposes of procuring a portfolio to provide SOS customer energy requirements and to meet the RPS, the expected energy savings from DSM programs needs to be subtracted from the Baseline Forecast of SOS customer energy. This result is termed the Reference Case Forecast. The Reference Case Forecast provides the mWh basis for determining the annual amount of Renewable Energy Credits needed for RPS compliance and the amount of annual energy expected to be procured through the Commission approved auction process for SOS customers.

Table 3 below summarizes the calculation of the Reference Case Forecast for all Delmarva Power customers in Delaware. Similar information for Delmarva Power SOS customers is provided in Table 4 below.[17]

Table 3
Summary Reference Case Forecast
All Customers

	2015	2020	2024
Baseline gWh less	8,189	8,190	8,234
DSM Savings (gWh) =	344	591	801
Reference Case Forecast	7,845	7,599	7,433

Table 4
Summary Reference Case Forecast
SOS Customers

	2015	2020	2024
Baseline gWh less	3,654	3,658	3,668
DSM Savings (gWh) =	300	518	699
Reference Case Forecast	3,354	3,140	3,018

[17] The Baseline Forecast for SOS customers includes the mWh for Hourly Service Customers.

Section V. Demand Side Management

Demand Side Management ("DSM") programs include energy efficiency programs, conservation programs, and demand response ("DR") programs. In contrast to supply side options such as new generating units, DSM programs reflect potential savings in either the total consumption of electrical energy, reduction of system demand during peak periods, or both. In the 2014 IRP, the expected energy and demand savings expected to occur due to the implementation of future DSM programs are subtracted from the Baseline Load Forecast prior to running the IRP planning model. In addition, demand side resources examined herein support compliance with the Delaware Energy Conservation & Efficiency Act of 2009.

Background

The Act designates energy efficiency as the first energy supply resource to be considered before any increase or expansion of traditional energy supplies. The Act created an Energy Efficiency Resource Standard ("EERS") requiring each Affected Electric Energy Provider[19] to achieve, at a minimum, energy savings equivalent to 15% of the Provider's 2007 electricity consumption, and a coincident peak demand reduction that is equivalent to 15% of the Provider's 2007 peak demand by 2015.[20] Pursuant to 29 *Del. C.* §8059, the SEU is tasked with coordinating and promoting the sustainable use of energy in Delaware. The Act directed that the SEU be responsible for implementing energy efficiency and conservation programs in Delaware while Delmarva Power be responsible for implementing Demand Response (DR) programs. The Act requires that Delmarva Power achieve the demand and energy reduction goals in coordination with the SEU and the Delaware Weatherization Assistance Program ("WAP").[21] Additionally, the current regulations governing the preparation of this and future IRPs states that it shall include:

> "...a detailed description of energy efficiency activities in accordance with 26 *Del. C.* §1020."[23]

Recently, however, legislation has been enacted which may affect the delivery of energy efficiency programs in Delaware. On August 6, 2014 the Delaware legislature passed SB 150 which permits Delmarva Power, in conjunction with the SEU, to offer energy efficiency

[19] An "Affected Electric Energy Provider" is defined as an electric distribution company, rural electric cooperative or municipal electric company serving Energy Customers in Delaware. 26 *Del. C.* §1501(1).
[20] *Id.* at 1502(a)(1).
[21] The Delaware Division of Energy and Climate also offers renewable energy and energy conservation programs for residential and non-residential customers.
[23] In the Matter of the Investigation Into the Adoption of Proposed Rules and Regulations to Accomplish Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company under 26 *DEL. C.* § 1007(c) & (d) (Opened August 7, 2007). PSC Regulation Docket No. 60.

programs and obtain cost recovery through base rates. The legislation also calls for the creation of an advisory council to recommend what programs Delmarva Power can offer and how they can propose and implement new programs.[24] While this legislation is likely to provide more opportunity for greater implementation of cost-effective DSM programs, the advisory council has not yet been formed and the procedures that Delmarva Power must follow to implement new DSM programs are still unknown. For this reason, the current IRP conservatively assumes that the SEU will be the sole provider of energy efficiency programs for the IRP PlanningPeriod. As the new rules and procedures allowing Delmarva Power to offer programs and recover costs are established, future IRPs will take this change into account.

In accordance with the Act, the EERS Workgroup was created to consider the various energy efficiency issues identified in the statute including providing guidance on the interpretation of the statute's targets. Delmarva Power was an active participant in this Workgroup. In June of 2011, the EERS Workgroup submitted to the Secretary of DNREC the "State of Delaware Energy Efficiency Resources Standards Workgroup Report" ("EERS Report"). The EERS Report, among other things, further defined the consumption and demand targets for the Affected Electric Energy Providers. The 2015 reduction goals for Delmarva Power were determined to be 284 mW for peak electricity demand and 1,329,054 mWh for annual electric energy consumption.

At this time, the Act and the EERS Report do not addresses what the consumption and peak demand reduction requirements will be after 2015. In the absence of a clear directive, Delmarva Power has assumed that the goal for each successive year after 2015 would be to continue calculating the goal as 15% of the EERS Report mandated 2007 consumption and peak demand minus each following year's otherwise forecasted incremental consumption and peak demand.

Estimated Overall DSM Cumulative Impacts

In prior IRPs, Delmarva Power has assumed that the energy and demand savings achieved by the implementation of SEU-sponsored programs would be sufficient to meet the targets set forth in the Act. However, in consultation with the IRP stakeholders and at the recommendation of the SEU, Delmarva Power has used the following methodology to forecast the energy and demand savings attributed to SEU-sponsored programs for the 2014 IRP.

First, the SEU provided estimates of their expected annual budgets over the planning horizon. For each year, the SEU provided a high and low case budget estimate from which an average budget was calculated. Next, the annual average budget estimates were

[24] More detail on this is provided in Section 2 of the IRP.

multiplied by an average cost per kWh saved to arrive at an estimated annual savings. To begin in 2015, the current average cost per kWh saved that Delmarva Power has achieved in its Maryland service territory with its Home Performance with Energy Star program was used. This value was increased each year until 2024 when it equaled the American Consortium for an Energy Efficient Economy ("ACEE") national average cost per kWh saved. Finally, these results were adjusted by the ratio of Delmarva Power's electricity distribution sales compared to the entire State of Delaware.

In addition to the SEU and WAP programs, Delmarva Power also implements and operates a number of energy savings programs targeted to its distribution and transmission systems. A summary of the cumulative energy and demand savings from all of these programs for the IRP Planning Period are shown in Table 1 and Table 2 below.

Table 1
Reference Case Energy Savings Estimates
(All Delmarva Power Delaware Distribution Customers)

MWH	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
DSM Initiative										
AMI Enabled Reductions	33,000	33,000	32,000	32,000	32,000	31,000	31,000	32,000	32,000	32,000
Distribution Efficiency Improvements	20,654	24,785	28,916	33,047	37,177	41,308	45,439	49,570	53,701	57,832
Transmission Efficiency Improvements	6,096	6,342	6,594	6,850	7,110	7,374	7,642	7,914	8,189	8,464
Combined Heat & Power	68,063	68,063	68,063	68,063	68,063	68,063	68,063	68,063	68,063	68,063
Street Lighting Improvements	2,783	2,896	2,896	2,896	2,896	2,896	2,896	2,896	2,896	2,896
Delaware Weatherization Assistance Program	4,424	5,308	6,193	7,078	7,962	8,847	9,732	10,617	11,501	12,386
Residential Direct Load Control	1,536	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086
Non-Residential Direct Load Control	0	102	732	1,260	1,289	1,316	1,345	1,367	1,391	1,416
Improved Codes and Standards	183,977	220,772	257,567	294,363	331,158	367,953	395,125	422,297	449,470	476,642
SEU EE Programs Case	4,440	7,830	11,799	16,392	21,749	28,175	36,202	46,893	62,894	94,687
Total Cumulative Energy Impact (MWh)	324,972	371,184	416,845	464,034	511,491	559,019	599,530	643,703	692,191	756,471

Table 2
Reference Case Demand Savings Estimates
(All Delmarva Power Delaware Distribution Customers)

MW	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
DSM Initiative										
AMI Enabled Reductions	93	92	91	91	91	91	92	93	94	96
Distribution Efficiency Improvements	2	3	3	4	4	5	5	6	6	6
Transmission Efficiency Improvements	2	2	2	2	2	2	2	2	2	2
Combined Heat & Power	9	9	9	9	9	9	9	9	9	9
Street Lighting Improvements	-	-	-	-	-	-	-	-	-	0
Delaware Weatherization Assistance Program	1	1	2	2	2	2	3	3	3	3
Residential Direct Load Control	32	43	43	43	43	43	43	43	43	43
Non-Residential Direct Load Control	-	2	15	26	27	27	28	28	29	29
Improved Codes and Standards	48	58	67	77	87	96	103	110	110	110
SEU EE Programs Case	1	1	2	2	3	4	5	7	9	14
Total Cumulative Energy Impact (MW)	188	212	235	257	269	281	291	302	306	313

Descriptions of the individual programs are provided below.

1. AMI Enabled Reductions

On March 23, 2011, Delmarva filed an Application to Implement an Advanced Metering Enabled Dynamic Pricing Plan and Dynamic Pricing Rider DP. On December 20, 2011, the Delaware Commission approved the Settlement Agreement entered into by Delmarva Power, Commission Staff and the Division of Public Advocate, and on January 31, 2012, issued its Final Findings, Opinion and Order (Order No. 8105) approving the proposed phase-in implementation of its Advanced Metering Infrastructure ("AMI") enabled Dynamic Pricing Program for its Standard Offer Service ("SOS") customers.[25] The approved rate is structured as a default Critical Peak Rebate ("CPR") rate with the ability for the customer to opt-out of the rate. The program is offered to all Delmarva Power residential SOS customers and will be available to all Delmarva Power small and medium non-residential SOS customers. The Program is currently titled the "Peak Energy Savings Credit Program."

In June 2013, the second phase of the Program began with the remaining Delmarva Power residential SOS customers being defaulted to the dynamic pricing rate. The final phase of Program implementation will begin in June 2015, when all Delmarva Power residential and small and medium non-residential SOS customers will be placed on the dynamic pricing rate.

Delmarva Power and the Brattle Group have performed a detailed study of the projected energy and demand savings attributable to the Dynamic Pricing Program in the Company's Delaware service territory based upon load reduction impacts from available comparable industry studies – the ongoing Baltimore Gas & Electric Company's ("BGE") dynamic pricing pilot, and the California statewide pricing pilot. The residential impacts of dynamic pricing programs in Delaware were estimated by adapting the Pricing Impact Simulation Model ("PRISM") developed through the California smart meter pilot studies, to the price elasticities that were estimated through the BGE study. Non-residential customer price elasticities were based upon results from the comprehensive California dynamic pricing pilots. All pricing estimates were adjusted for Delaware load shapes and weather conditions.

The dynamic pricing impact study excluded the load impacts of Delmarva Power's existing and planned Direct Load Control program, the projected energy efficiency and conservation savings expected to be achieved by the SEU, and energy and demand savings from other identified sources. These adjustments lessen the estimated demand savings that will be achieved by dynamic pricing programs; therefore, if reductions from other sources are not achieved, demand reductions from dynamic pricing are expected to be higher. Dynamic pricing is expected to provide 93 MW of peak demand reduction by 2015. In the event that PJM wholesale electricity market conditions for the Delmarva Power Delaware region change, dynamic pricing incentives can be adjusted to reflect those changes.

[25] PSC Docket No. 09-311.

Delmarva Power's AMI deployment has enabled the Company to provide additional detailed electric energy use information to all residential and small commercial customers. The additional energy usage information is now available through Delmarva Power's monthly electricity bills and its "My Account" web portal. Delmarva Power provides energy savings tips through the My Account web portal and via its call center through its Energy Advisors. Delmarva Power has estimated that residential customers will reduce their energy consumption by 1.5% annually due to the availability of this detailed energy use information.[26]

2. Transmission and Distribution System Improvements

Electric distribution transformers are evaluated consistently throughout the PHI utility companies using the minimum efficiency tables contained in NEMA TP1-2002, Section 4. At the time that the U.S. Department of Energy ("DOE") issued their Final Ruling in 2007 to establish more stringent minimum efficiency levels, Delmarva Power was already investigating methods to increase the minimum efficiency levels. Beginning in 2008, Delmarva Power purchased transformers consistent with DOE's TSL-2 level efficiency criteria.

3. Combined Heat and Power ("CHP") Potential

CHP offers a potentially efficient and clean approach to generating electricity or mechanical power and supplying useful thermal energy from a single fuel source at the point of use. Instead of purchasing electricity and also burning fuel in an on-site furnace or boiler to produce thermal energy, an industrial or commercial facility can use CHP to provide these energy services in one energy-efficient step. As a result, CHP can provide significant energy efficiency and environmental advantages over separate heat and power supplies. CHP systems are located at or near end-users, and, therefore, lessen or defer the need to construct new transmission and distribution (T&D) infrastructure. While the traditional method of producing separate heat and power has a typical combined efficiency of 45%, new CHP systems can operate at efficiency levels as high as 80%. CHP's high efficiency results in less fuel use and lower levels of greenhouse gas emissions. To estimate the savings attributed to CHP in Delmarva's Delaware service territory, Delmarva Power only included the current CHP systems in operation, or those in the process of being constructed.

4. High-Efficiency Streetlamps

As a result of EPACT 2005, the Federal government banned the manufacture and importation of Mercury Vapor streetlight ballasts, effective January 1, 2008. After a review of options, Delmarva Power implemented a plan to proactively replace MV streetlights over a five

[26] See also a paper by Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence", *Energy: The International Journal*, April 2010.

year period with High Pressure Sodium streetlights. These replacements reduce energy consumption, and provide superior lighting performance for Delmarva Power customers.

5. The Delaware Weatherization Assistance Program ("WAP")

WAP installs energy efficiency improvements in low-income households. Specifically, WAP provides for the installation of such measures as: air sealing, insulation, window and door replacement, and furnace repair and replacement. Based on an analysis of electrically-heated homes prepared by the University of Delaware's Center for Energy and Environmental Policy, WAP estimates kWh savings of 22% on average per household as a result of these improvements. In program year 2009 (4/1/09 – 3/31/10) the WAP served a total of 1,221 homes statewide. WAP plans to serve approximately 1,100 homes during each program year going forward.

6. Demand Response Programs

Delmarva Power is responsible for implementing demand response programs within its service territory, although additional demand savings will result from the SEU's energy efficiency and conservation programs and all other energy savings sources with the exception of street-lighting improvements. Delmarva Power has two direct load control programs currently implemented in addition to the Dynamic Pricing program previously discussed, and has developed demand response potential projections for one other program. These three combined programs address all customer market segments for Delmarva Power Delaware. These programs have been designed specifically to participate in available demand response market opportunities under the current market rules within the PJM capacity and energy markets. Participation in these current markets provides a revenue stream that offsets a portion of program costs, provides PJM dispatchers demand response programs that can be used to help maintain system reliability during high load periods, and helps to mitigate high regional electricity market capacity and energy prices. The programs can also be used by Delmarva Power to help manage localized distribution system problems depending upon their location and scale. Demand Response programs help to defer the need to construct additional generation resources, transmission facilities, and distribution facilities. The programs can also assist with the integration of renewable generation sources, such as wind power, due to its uncertain availability during periods of high electricity demand. Finally, the programs offer consumers a direct method of reducing their monthly electricity bills through both incentives for participating in each program and the reduction of energy consumption during specific periods of time.

a. Residential Direct Load Control

On December 18, 2012, Delmarva Power received Public Service Commission approval for its proposed Residential Direct Load Control Program ("DLC").[27] The program, titled the Energy Wise Rewards™ is a voluntary customer program designed to update, expand, and replace the legacy "Energy For Tomorrow" central air conditioning/heat pump load control program with newer technology. The program provides a voluntary and simple method for residential consumers with central air conditioning or heat pump systems to automatically reduce peak electricity demand during peak usage periods, and to also reduce their overall air conditioning and heating system energy consumption. The program accomplishes this through the installation of either a remotely controllable smart thermostat or direct load control switch (participating customers have the option of choosing either of the devices). These devices reduce the air conditioner load on the electric system after receipt of a Delmarva Power command signal. The smart thermostats are capable of being programmed to automatically vary temperature settings, thereby providing added energy savings opportunities. The planned program will be integrated with Delmarva Power's AMI system.

As shown in Table 2 above, available peak demand reduction capability for the Residential DLC Program is projected to be 32 MW by the summer of 2015. Associated energy savings are estimated to exceed 2,000 mWh by year-end 2015.

b. Non-Residential Direct Load Control

The primary objective of the voluntary Non-Residential Load Control Program is to provide a simple method for non-residential consumers with central air conditioning or heat pump systems to automatically reduce peak electricity demand during peak usage periods, while also reducing their overall electricity consumption. Similar to the DLC, this program will provide the installation of either a remotely controllable smart thermostat or a direct load control switch (participating customers will have the option of choosing either of the devices).

7. Codes and Standard Savings

Delmarva Power has considered the potential savings impact of Code and Standard improvements in Delaware in calculating the total attainable demand and energy consumption savings. The major impacts from Codes and Standards that are currently in effect are air conditioning minimum efficiency requirements and Federal lighting efficiency requirements which went into effect beginning in 2011. Since the SEU energy efficiency programs are likely to contain residential and non-residential lighting efforts as part of the Home Performance with Energy Star

[27] PSC Order No. 8253, Docket No. 11-330.

and other Commercial programs that extend through 2017 separately, the Codes and Standards impacts of the lighting efficiency requirements could result in potential double counting of savings. Therefore, only the impact of the air conditioning minimum efficiency requirements that are not captured by the identified SEU programs were estimated.

The basis for the analysis is that there are energy savings that are not captured in energy efficiency programs which result from the higher minimum efficiency requirements. When an air conditioner is replaced, the current minimum efficiency is significantly higher than the original unit that was replaced. Since an efficiency program only claims savings that are above the required minimum efficiency, any savings resulting from reaching the minimum efficiency levels are not accounted for in the efficiency program impacts. An analysis was performed to estimate the impacts resulting from the higher minimum efficiencies required for residential and non-residential air conditioning replacement.

8. SEU

The savings attributable to SEU activities were calculated per the methodology described earlier in this Section.

Section VI. Transmission

Delmarva Power's transmission facilities are located within the RTO. Delmarva Power works with PJM to ensure that reliability standards are met and that the necessary transmission facilities are built to meet the short and long term needs of the Delmarva Peninsula.

PJM, as the RTO, is responsible for ensuring:

- Adequate generation or demand side resources across the entire region; and
- Adequate transmission capacity to reliably and efficiently deliver the generation capacity where it is needed.

PJM meets these objectives by administering competitive markets that encourage merchant generation, transmission and demand-side resources. In addition, PJM, as the regional planner, identifies violations of the PJM planning criteria and works with Delmarva Power's Transmission Planning Department to verify the accuracy of the violations and determine the most appropriate system upgrades to mitigate those violations. The selected upgrades are ultimately included in the PJM Regional Transmission Expansion Plan ("RTEP").

The Federal Energy Regulatory Commission ("FERC") issued Order 1000 on July 21, 2011 (the "Order"). This Order required changes to the Transmission Planning and Cost Allocation processes. To comply with the Order, PJM has implemented a competitive solicitation process to address violations of the PJM planning criteria. Stakeholders have been working through the PJM Regional Planning Process Task Force ("RPPTF") to revise the affected PJM planning protocols to align them with the requirements outlined in the Order. . The Order can be reviewed in its entirety, along with the subsequent FERC Order 1000-A on the FERC website (http://www.ferc.gov/). The Order addresses the following topics: planning requirements inclusive of local, regional and interregional transmission planning processes; public policy requirements advising consideration of transmission needs driven by public policy; the Right of First Refusal including the development of transmission facilities by non-incumbent developers', and cost allocation requirements specific to transmission cost allocation policies. The content of PJM stakeholder meetings can be viewed via the RPPTF link on the PJM website.

The first FERC Order 1000 Request for Proposal (RFP) window closed in June 2013, which addressed stability issues associated with Artificial Island. PJM is focusing on solutions from "finalist" bidders and plans to award a project by the end of 2014. The 2014 RTEP is the first RTEP analysis to be evaluated through the FERC Order 1000 process. PJM has completed review of the proposals submitted in this window and plans to make a recommendation to the PJM Board of Managers in November 2014.

PJM's planning process is a rigorous 24-month process, which uses a 15-year horizon, as outlined in PJM Manual 14-B, available on the PJM website. The 24-month planning process is made up of two similar 12-month planning cycles to identify and develop shorter lead-time transmission upgrades, and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. The planning process takes into account the requirement that the future transmission system must meet all applicable reliability criteria including North American Electricity Reliability Council ("NERC"), Reliability First Corporation ("RFC"), PJM and Delmarva Power local planning criteria. PJM tests the system under both expected normal peak conditions, and extreme conditions where peak loads are higher than forecasted and there are more generating units out of service than would be expected under normal peak conditions. Based on this analysis, PJM, with support from Delmarva Power, develops a detailed immediate need (less than 3 years out) plan to ensure that the transmission system has sufficient capability to serve the load, and that generation resources within PJM are deliverable. PJM develops the near term (4 -5 years out) and long range (15 years out) plan through the FERC Order 1000 competitive solicitation process. The transmission system plans that are developed include upgrades and additions to the transmission system, as well as new reactive sources, to ensure that adequate transmission system voltages are maintained under all tested conditions. The load flow cases on which the plan is based include all assumptions about the expected load forecasts, the Demand Response programs, and the proposed generation available.

Table 1 below lists pending individual transmission system upgrades that comprise the RTEP projects in Delaware. A short description of each project as well as the PJM project identification number, expected in-service date and estimated project cost are provided in the table. The information listed is also available on the PJM website. PJM will finalize a complete list of projects by the end of the year that will be used as part of the 2014 RTEP report, to be issued by February 2015.

Table 1 – Delmarva Transmission System Planned Upgrades

Upgrade ID#	Description	In-Service Date	Estimated Cost ($M)
b1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV	12/31/2014	$0.00
b0879	Build a new Wye Mills-Church 138 kV line	6/1/2015	$35.36
b1247	Re-build the Glasgow - Cecil 138 kV circuit	6/1/2015	$5.96
b1248	Install two 15 MVAR capacitor at Loretto 69 kV	6/1/2015	$1.30
b1249	Reconfigure the existing Sussex 69 kV capacitor	6/1/2015	$0.78
b1603	Upgrade 19 miles conductor of the Wattsville - Signepost - Stockton - Kenney 69 kV circuit	6/1/2016	$15.00
b1723	Replace strand bus and disconnect switch at Glasgow 138 kV substation	6/1/2016	$0.08
b1604	Replace CT at Reybold 138 kV substation	6/1/2016	$0.08
b2288	Build a new 138kV line from Piney Grove - Wattsville	6/1/2018	$25.00
b2395	Reconductor the Harmony - Chapel St 138 kV circuit	6/1/2018	$1.62
b2569	Replace Terminal equipment at Silverside 69 kV substation	6/1/2019	$0.04

Table 2 below shows Delmarva Power transmission projects, by year, that were constructed since the 2012 IRP. The projects addressed reliability concerns and were identified to resolve violations flagged by PJM in their RTEP process. In addition, these projects helped mitigate economic concerns by lowering congestion hours for all Delaware customers.

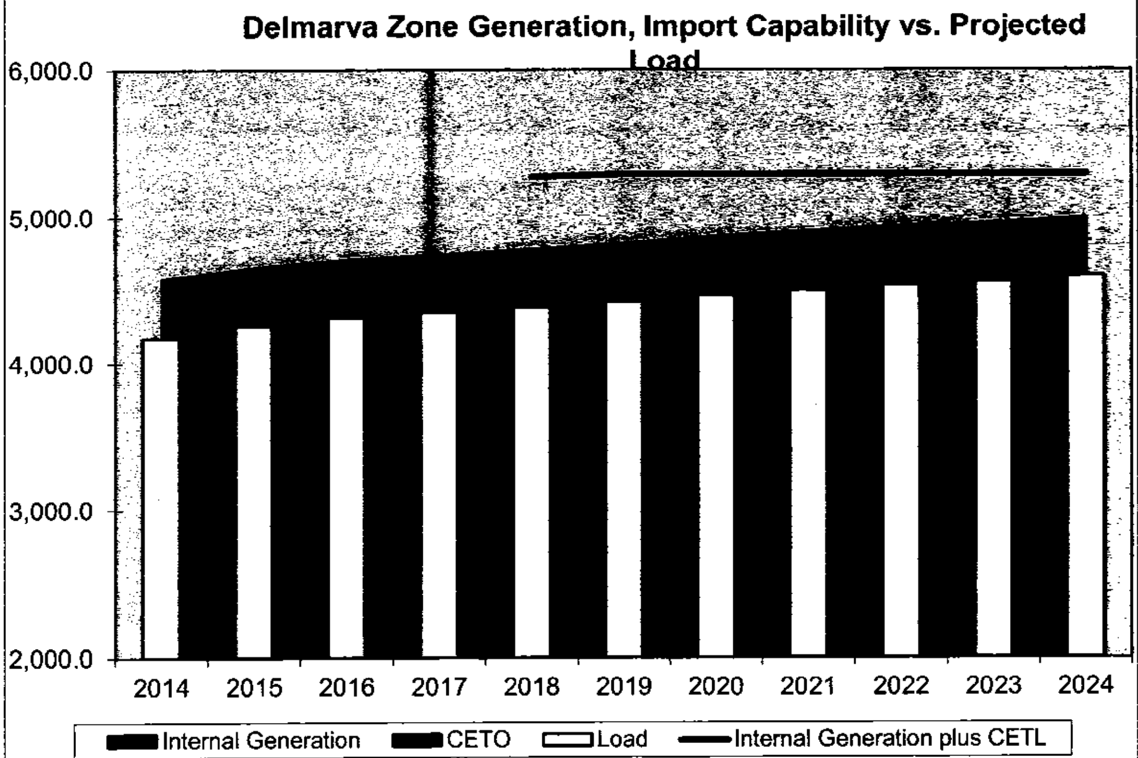
Table 2 – Delmarva Power Transmission System Upgrades Completed

Description	In-Service Date	Cost($M)
Rebuild Trappe Tap to Todd 69 kV line	12/31/2012	$12.00
Install new variable reactors at Indian River and Nelson 138 kV	12/31/2012	$11.00
Add a 3rd Steele 230/138 kV transformer	6/1/2013	$9.75
Add a 2nd Harmony 230/138 kV transformer	6/1/2013	$14.82
Build a new Indian River-Bishop 138 kV line	6/1/2013	$18.00
Add two additional breakers at Keeney 500 kV	6/1/2013	$4.50
Rebuild the entire Glasgow to Mt. Pleasant 138 kV line	6/1/2013	$16.34
Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, remove relay limits on Cecil-Colora 230 kV line & Cecil-Glasgow 138 kV line ,and operate the 34 kV bus normally open	6/1/2013	$6.00
Build 2nd Glasgow-Mt Pleasant 138 kV line	6/1/2013	$16.30
Reconfigure Brandywine substation	6/1/2013	$8.43
Apply a special protection scheme (load drop at Stevensville and Grasonville)	6/1/2013	$0.05
Maridel to Ocean Bay (6723-1) Rebuild	12/31/2013	$1.62
Install 75 MVAR SVC at 138th St 138 kV bus	12/31/2013	$22.80
Install new variable reactors at Cedar Creek 230 kV	12/31/2013	$2.86
Rebuild Vaughn-Wells 69 kV line	6/1/2014	$1.18
Reybold - Lums Pond 138 kV: Replace two circuit breakers to bring the emergency rating up to 348 MVA	6/1/2014	$1.00
Re-build the Townsend - Church 138 kV circuit	6/1/2014	$16.00

As previously noted, in addition to the detailed plans developed for the next five years, PJM also works with stakeholders, including Delmarva Power, to develop a 15-year plan which addresses the need for new major "backbone" transmission projects at higher voltages. Currently, there are no planned major backbone transmission projects in Delaware.

The graphical data in Figure 1 below shows the import capability into the Delmarva zone with respect to the zonal load. The Capacity Emergency Transfer Objective (CETO) target was calculated and published by PJM for study year 2017. CETO values for years prior to and after the study year was extrapolated based on the 2017 value and the yearly change in the forecasted load. The Capacity Emergency Transfer Limit (CETL) target was calculated and published by PJM for study year 2017. PJM plans for a minimum CETL to CETO ratio of 115%. The chart below conservatively holds CETL values for years 2019 – 2024 constant. The slight rise in the "Increased Generation plus CETL" value in 2019 is attributed to increased generation on the Delmarva Power system. Based on PJM's published CETL to CETO value of greater than 115% for Delmarva Power in 2015, it is not anticipated that the CETO value will exceed the CETL value within the Delmarva zone over the planning horizon. The data presented in Figure 1 below illustrates that over the IRP Planning Period, it is expected that there will be sufficient generation and transmission resources to meet projected zonal load and PJM planning objectives.

Figure 1 – Delmarva Zone Generation, Import Capability vs. Projected Load



Capacity Emergency Transfer Objective (CETO) - is the targeted import capability objective into the area to meet established regional reliability margins.
Capacity Emergency Transfer Limit (CETL) - is the estimated/calculated import capability into the area. 2018 CETL values as listed in PJM 2018 RTEP Base Case documentation from 4/10/14 PJM TEAC. CETL conservatively held flat for future

Sources: Projected Load: PJM Load Forecast Report dated Jan 2014
Generation Data: 2010 PJM Load, Capacity and Transmission Report dated December 28, 2011,
http://phx.corporate-ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=1719378&highlight=
Generation includes the retirement of Indian River #3 in 2013, new Calpine generator in 2015, and retirment of McKee Units 1 & 2 in 2017.
Generation additions with signed ISAs submitted through the PJM Queue Generation Interconnection Process have been included.

Contingency Plan

The PJM RTEP considers the immediate, near-term, and long-term needs of the regional transmission system and is updated on an annual basis. Delmarva Power actively participates in this process and carefully monitors new developments. As new information becomes available and new decisions are made through the RTEP process, Delmarva Power evaluates and updates its plans as needed.

Section VII: IRP Reference Case Supply Side and Environmental Assumptions

This Section describes some of the key inputs and parameters of the 2014 IRP Reference Case related to generation resources including capital costs, expected fuel prices and environmental regulations.

A. CAPITAL COST PROJECTIONS

In evaluating potential capacity additions for meeting future demand requirements, Pace Global assessed several generation technologies' maturity levels and operating histories. Based on Pace Global's review of available generation technologies and other public sources for capital cost data, estimates for new technology costs were developed.

Pace Global's estimates have taken recent trends in commodity price inputs into account. Pace Global has projected trends in technology, materials, and labor costs in order to value early, middle, and late time period cost assumptions. The early time period reflects 2014-2016, the middle time period represents 2017-2024, and the late time period is for 2025-2030.

Table 1 below highlights the national average for new technology parameters, with the relevant regional multipliers shown in Table 2 below.

Table 1: New Resource Technology Parameters

Technology	Early Capital Cost (2014-2016)	Mid Capital Cost (2017-2024)	VOM	FOM	Average Heat Rate	Block Size
	$/kW	*$/kW*	*$/MWh*	*$/kW-yr*	*Btu/kWh*	*MW*
CC (FA)	1,033	962	3.19	9.92	6,900	623
CT (FA)	726	676	0.92	17.87	10,041	206
Advanced CT (LMS 100)	1,085	983	4.54	15.00	9,191	100
Solar PV	2,362	1,987	0.00	24.77	-	7
Wind 1.5 MW	1,885	1,757	0.00	29.79	-	50

Source: Pace Global

Table 2: Regional Multipliers for Capital Costs

Zone	Regional Multiplier
PJM East	1.19
PJM - COMED	1.14
PJM - West	1.05

Source: Pace Global

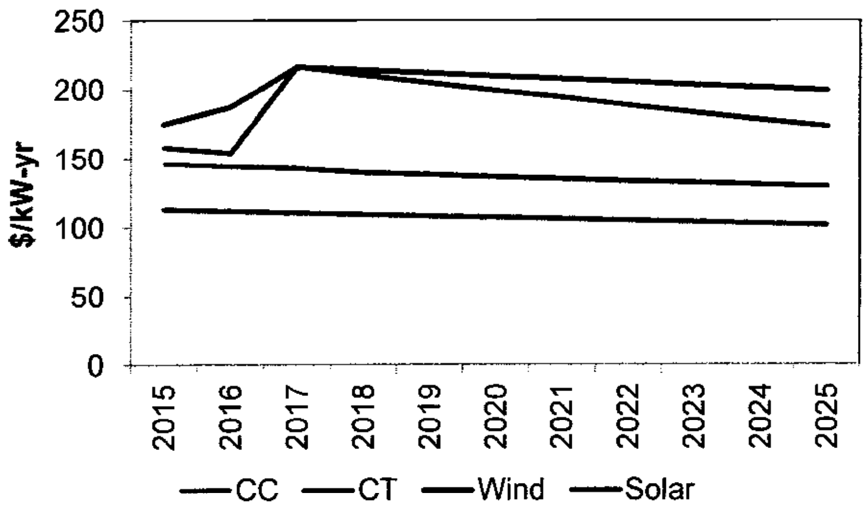
In assessing the economics of new technology additions over the course of the Study Period, Pace Global considers revenues from the power markets against levelized recovery targets for new unit construction. The levelized recovery targets for each unit type are derived from capital cost estimates over time, fixed operating and maintenance costs, and financing assumptions. Pace Global assumes a 50:50 debt to equity ratio, with a 15.7 percent required return on equity and a 7.75 percent interest rate on debt. Renewable technologies are evaluated in the context of appropriate tax depreciation schedule benefits and other incentives like the federal production tax credit and investment tax credit. Table 3 below summarizes Pace Global's expected value levelized recovery requirements for new resources. The sharp increase in the recovery requirements for new solar and wind units in the 2017-2024 period is driven by the rolling off of the Investment Tax Credit ("ITC"). This is also shown graphically Figure 1 below. Pace also applied regional multipliers to represent the differing costs of construction and tax regimes in these regions.

Table 3: Expected Case Recovery Requirements for Various Technologies (2013$)

Technology	Early Capital Cost	Mid Capital Cost	Early Levelized Recovery Requirement	Mid Levelized Recovery Requirement
	(2014-2016)	(2017-2024)	(2014-2016)	(2017-2024)
	$/kW	*$/kW*	*$/kW-yr*	*$/kW-yr*
CC (7FA)	1,033	962	146	137
CT (FA)	726	676	113	107
Advanced CT (LMS 100)	1085	983	158	145
Solar PV	2,362	1,987	159	197
Wind 1.5 MW	1,885	1,757	181	209

Source: Pace Global.

Figure 1: New Resource Levelized Recovery Requirements (2013$)



Source: Pace Global.

Combustion Turbine Based Plants

Combustion turbine plants include current combined cycle and simple cycle plants, and next generation combined cycle plants represented by the "H" technology. In the near term, industry standard technologies like General Electric (GE)'s 7FA 1x1 and 2x1 configuration will remain the standard combined cycle configuration. GE's aero-derivative-based LM6000 will likely remain the standard for simple cycle uses and for smaller combined cycle stations (less than 60 mW).

Over the next five years the newest "H" technology is likely to gain market share without supplanting the current 7FA standard model. These machines have lower capital, operations, and operations and maintenance (O&M) costs, and have operating efficiencies over 60 percent.

Combustion Boiler Based Plants

Power plants burning gas, oil, coal or biomass comprise this category and are not expected to undergo significant technology or cost changes over the next 20 years. Coal-fired power plant oversight costs are expected to fall at a real rate of 0.3 percent per year according to the EIA. The same decline is expected for biomass-fired boiler based plants.

Solar-Based Power Plants

Utility scale solar power plants are either photovoltaic ("PV") or Concentrated Solar Power ("CSP") technology. In either case, the technology is relatively new and, as such, costs are expected to decline over the next few years as the technology matures. When analyzing and determining generic unit additions, Pace Global focuses on large scale solar installations. Nominal equipment prices are expected to decline significantly, while labor increases at 0.5 percent per year.

Wind

Wind turbine technology is fairly mature and, as such, prices are not expected to decline substantially. However, larger wind turbines are becoming more common and should see a reduction in the nominal per unit cost over the next few years. For all wind turbine plants, nominal equipment prices are expected to decline 0.5 percent per year, while labor is expected to increase 0.5 percent per year.

Environmental Retrofit Costs

Environmental retrofit costs represent an area of significant required investment for coal plants looking to comply with EPA regulations. Pace Global's retirement analysis assesses capital expenditures on environmental retrofits when assessing coal plant economics and potential retirement. Table 4 below displays the base capital costs for the three major retrofit installation types used in the analysis.

Table 4: Summary of Environmental Retrofit Capital Costs (2013$)

Technology	Capital Cost
	$/kW
Wet Scrubber	511
SCR	181
Fabric Filter	81

Source: Pace Global, EIA, and EPA

B. REGIONAL GAS PRICES

Pace Global's regional gas price forecasting methodology incorporates regional supply basins, demand locations, and relevant pipeline infrastructure in order to project unique delivered gas prices across the entire PJM footprint. A more detailed discussion of Pace Global's assessment of major fuel markets is provided in Appendix 7.

TETCO M-3

The most relevant liquid hub for the DPL zone is TETCO M3. In 2013, over 24,000 trades (nearly 130,000,000 MMbtu worth of gas) were made, making TETCO M-3 the 7th most active trading point. TETCO M-3 is a benchmark for gas pricing in the region north of Baltimore up to the outskirts of New York City, and frequently trades on top of the nearby Transco Zone 6 non-NY hub (which only saw 12,000 trades in 2013 for 66,000,000 MMBtu of gas). Because of the significant transmission flows from PJM-West to the more densely populated eastern regions, TETCO M3 gas pricing is most often the price at which the marginal resource is priced, which tends to drive up energy prices in the region.

TETCO M-3 is trading by as much as -1.00 below Henry Hub in the summer time due to the significant level of Marcellus production flowing into the region. However, summer prices are expected to rise to parity with Henry Hub by 2018 as demand rises and as Marcellus production is diverted elsewhere with the completion of new Market-to-Gulf Coast pipeline projects, such as those enumerated above. In the winter months, transmission capacity constraints continue to dominate during peak demand times. Winter price spiking is expected to continue for the foreseeable future, albeit attenuating down from +4.00 in January 2015 to +1.68 in January 2020. Overall, TETCO M-3 basis is trending downward, reaching negative values by the end of the Study Period.

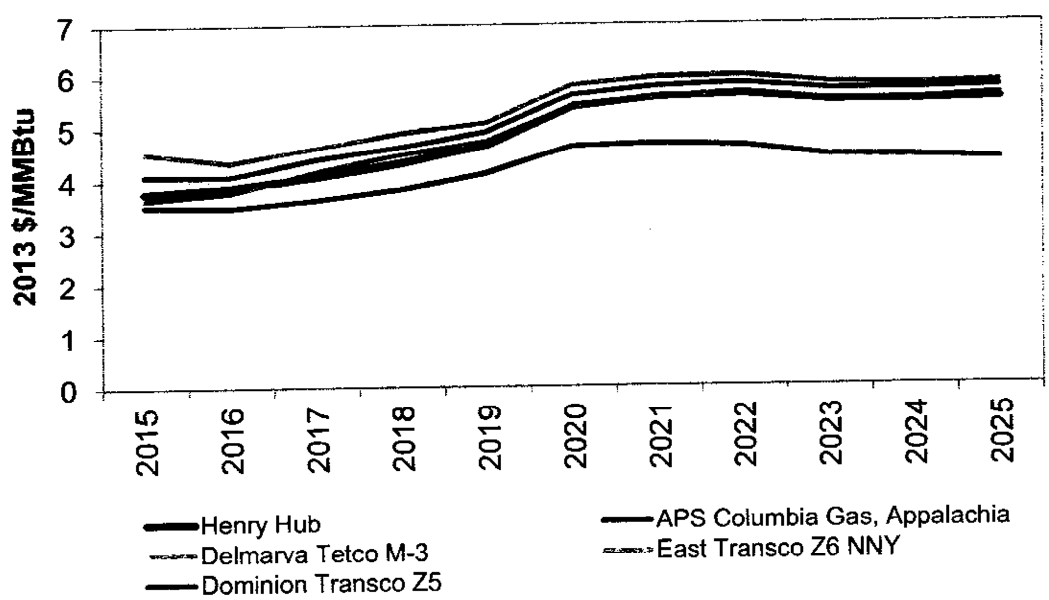
Table 5 and Figure 2 below summarize the reference case natural gas prices for the Henry Hub and associated regional basis points. Table 5 shows the basis for several key points within PJM, while Figure 2 graphs the delivered prices for a selection of major hubs.

Table 5: Natural Gas Price Basis Projections – Reference Case ($/MMBtu)

Year	Henry Hub	AEP	APS	ComEd	Delmarva	East	ATSI	PENELEC	Dominion
		Lebanon	*Columbia Gas, Appalachia*	*Chicao Citygates*	*Tetco M-3*	*Transco Z6 NNY*	*Columbia Gas, Appalachia*	*Dominion South. Tetco M-3*	*Transco Z5*
	$/MMBtu	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*
2015	3.77	-0.30	-0.27	0.11	-0.13	0.76	-0.27	-0.59	0.33
2016	3.88	-0.43	-0.41	-0.01	-0.10	0.47	-0.41	-0.52	0.21
2017	4.08	-0.37	-0.46	-0.02	0.10	0.55	-0.46	-0.30	0.32
2018	4.33	-0.29	-0.50	0.03	0.16	0.57	-0.50	-0.33	0.31
2019	4.67	-0.21	-0.53	0.01	0.08	0.42	-0.53	-0.53	0.25
2020	5.39	-0.21	-0.75	-0.02	0.01	0.43	-0.75	-0.70	0.24
2021	5.57	-0.22	-0.88	-0.05	0.02	0.40	-0.88	-0.76	0.22
2022	5.63	-0.24	-0.98	-0.06	0.01	0.37	-0.98	-0.83	0.22
2023	5.50	-0.23	-1.05	-0.06	0.02	0.35	-1.05	-0.86	0.22
2024	5.49	-0.24	-1.08	-0.07	0.02	0.32	-1.08	-0.91	0.22
2025	5.53	-0.24	-1.17	-0.07	0.08	0.32	-1.17	-0.92	0.23

Source: Pace Global.

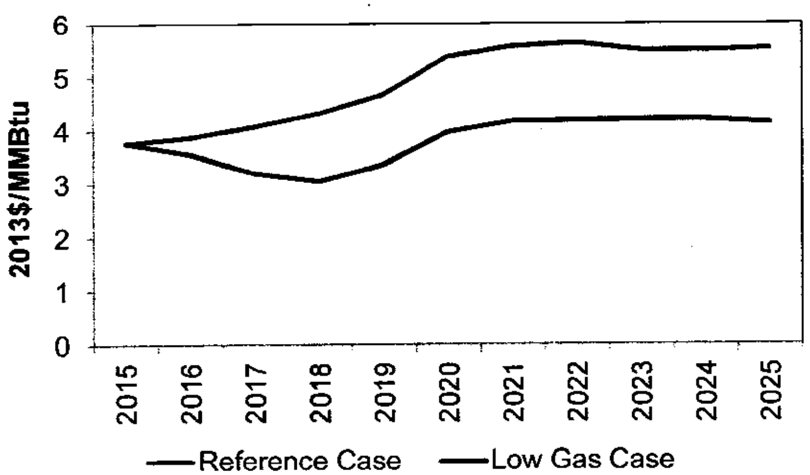
Figure 2: Reference Case Natural Gas Price Projections for Relevant Gas Hubs (2013$)



Source: Pace Global.

In order to assess the impact of lower natural gas prices on the PJM power market, Pace Global developed a low natural gas price scenario that presumes more abundant domestic supply at lower production costs than those assessed in the reference case. Figure 3 below summarizes the price projections for both the reference case and low gas case at the Henry Hub.

Figure 3: Henry Hub Reference Case and Low Gas Case Scenarios (2013$)



Source: Pace Global.

Generally, a low gas price case will stimulate a higher rate of demand from most sectors, particularly the price sensitive power generation sector and, to a lesser extent, the industrial sector. The low gas price case sees gas-fired power generation demand grow to 35.2 Bcf/d in 2020 and 42.8 Bcf/d in 2025 vs. 31.4 Bcf/d in 2020 and 34.5 Bcf/d in 2025 in the reference case. Industrial sector demand for natural gas also is higher, growing to 27.2 Bcf/d by 2025 in the low gas price case vs. 24.4 Bcf/d in the reference case, as industrial users (particularly from ethylene crackers, ammonia/urea/fertilizer plants, and gas-to-liquids plants) take advantage of the sustained low price environment and invest in long-term production facilities.

Given higher gas demand, both production and infrastructure build-out are assumed to be substantially higher in the low gas price case than in the reference case in order to keep downward pressure on prices. In terms of supply in the low gas price case, the price of WTI crude oil maintains in the $95/bbl range (versus the $85/bbl where current forwards are headed and where the reference case is set). As a result, the associated gas produced from oil-directed drilling as well as the revenue uplift from natural gas liquids helps buoy gas supply and keep a ceiling on gas prices. Drilling productivity is assumed to continue to grow robustly as producers gather more and more fracking data and adjust their drilling patterns to increase production while decreasing costs. Flaring is reduced in places like North Dakota, contributing to the gas supplies.

Importantly, in the low gas price case, many of the proposed pipeline projects are completed (and more so than in the IRP Reference Case), particularly the 12-15 Bcf/d of takeaway pipeline capacity currently proposed for the Marcellus and Utica region. The ability to move rapidly rising gas production in the Appalachian basin to premium markets in the Gulf Coast, the Southeast, and the Northeast help to keep downward pressure on prices in these regions and in the U.S. in general. Absent a high level of pipeline build-out, the U.S. will not benefit as efficiently and uniformly from the substantial lower gas prices seen at Dominion South Point and TCO Pool in the Marcellus/Utica regions.

C. ENVIRONMENTAL REGULATIONS

Carbon Dioxide

The New Source Performance Standard for Electric Generating Units

In September 2013, the EPA released the updated New Source Performance Standards ("NSPS") for Electric Utility Generating Units, a proposed regulation that would establish carbon dioxide (CO_2) emission limits for ***new*** power plants in the continental United States. The NSPS, as proposed, sets a rate limit of 1,000 lbs of CO2/mWh for combined cycle natural gas plants and a limit of 1,100 lbs of CO2/mWh for coal plants. The NSPS effectively prevent the permitting of new coal-fired power plants that are not equipped with CO_2 pollution control equipment such as Carbon Capture and Sequestration ("CCS"), a technology that has yet to be deployed on a commercial scale.

Despite the effective ban the NSPS places on new coal-fired units that lack CCS, Pace Global anticipates that the implementation of this rule, in isolation, would have a limited near-term impact on power markets in the U.S. Other market factors – such as cheaper-to-build gas plants, low natural gas prices, and other environmental regulations expected to increase compliance cost burdens for new (and existing) coal-fired electricity generation – have made conventional coal an unlikely option for supplying significant new generation capacity in the U.S. Thus, even in the absence of this rule, Pace Global does not expect any significant build out of additional coal capacity in the near future.

Performance Standards for Existing Generating Units

The EPA released the draft performance standards, also known as the Clean Power Plan (CPP), for existing generating units under §111(d) of the CAA on time on June 2, 2014. The CPP establishes state by state emission rate targets for covered existing generation units. Overall, the proposed rate targets would reduce emissions from affected sources by 30% below 2005 levels by 2030. The final rule is due in June 2015, with state implementation plans due between 2016 and 2018. States will have initial targets starting in 2020, with the final target to be achieved by 2030.

The draft rule allows for states to comply with the standards in a flexible manner, with many considering potential strategies for renewables, efficiency, and other changes to the resource mix. Ultimate rule implementation and state plan development is likely to extend through the decade or beyond.

Carbon Pricing

Given the high level of uncertainty around federal carbon regulation in the U.S., Pace Global has not included a carbon price in the IRP Reference Case PJM projections.

Mercury and Air Toxics Standards (MATS) Rule

EPA's Mercury and Air Toxics Standards Final Rule (MATS), originally issued in December 2011, requires facility specific emission reductions of mercury, acid gases, and particulate matter. This is a command-and-control type of regulation with no allowance trading. The rule comes into effect in April of 2015 and existing plants can apply for a one year extension to reach compliance. MATS sets a decision point for generators – control or retire – even if cost drivers may come after 2016. Several groups have filed lawsuits that center around the standards, need for additional time and flexibility for compliance, and the NSPS that are included in the rule, though it is not expected that the lawsuits will be successful in changing the content or implementation of the rule at this point.

In March 2013, EPA finalized updates to the NSPS standards related to MATS. These updates do not have a material impact on the existing units and the need for controls. The MATS rule has been one of the main drivers of the retirement of older coal plants as operators weigh the cost of compliance against continued operation. In the PJM region, this rule, in combination with the low gas prices, has been a major force behind the recent and expected retirements of large amounts of coal and oil/gas fired capacity.

SO_2 and NO_x Prices

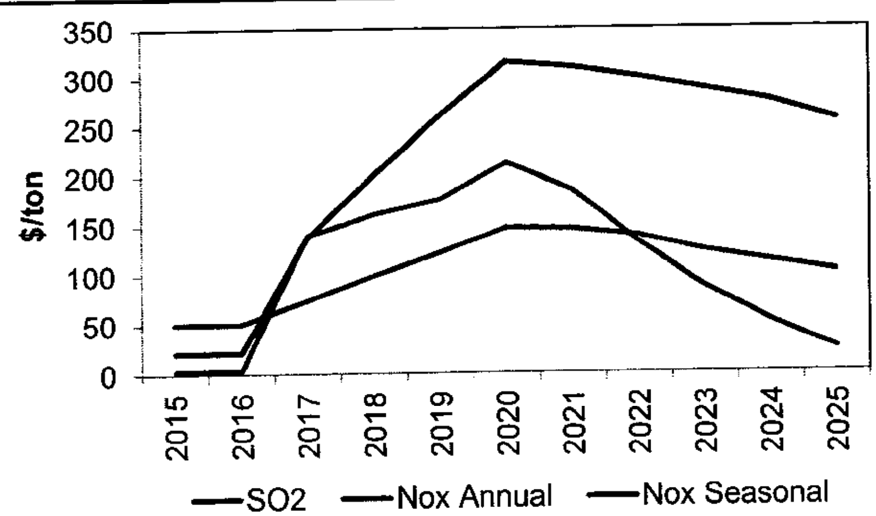
On April 29, 2014, the Supreme Court of the United States upheld the EPA's Cross State Air Pollution rule (CSAPR). The EPA is required to assess the interstate transport of pollutants and regulate emissions that impact the ability of downwind states to meet national ambient air quality standards (NAAQS). Initially slated for implementation in January 2012, the rule was challenged and later in 2012 was vacated by the Circuit Court of the District of Columbia. The predecessor and less stringent rule, the Clean Air Interstate rule (CAIR), has been in place since the vacation of CSAPR.

Exactly what the Supreme Court's decision means for the future implementation of a transport rule is not clear at this time. First, a number of other legal challenges to CSAPR that were outside of the purview of arguments heard by the Supreme Court remain. As such, the potential for additional legal review and associated delays remains. Next, we know that the EPA is currently reviewing the Supreme Court decision and will then consider next steps to address and ultimately implement a transport rule. It is expected that another two or more years will pass before the next draft of the rule will be released. The EPA could conceivably set new caps based on more recent data which could lead to state-level emission caps that are more stringent than what was included in CSAPR.

Even without a clear picture of what the compliance requirements of the final transport rule will be or when it will be implemented, Pace Global does not expect a significant increase in allowance costs for the covered pollutants (SO_2 and NO_x) over our prior outlook which was based off of the emission caps under CAIR. Recent and planned coal plant retirements and retrofits, largely as a compliance strategy for the EPA's MATS have and will continue to reduce emissions of covered generators significantly over the next couple of years. Specifically, retrofits to meet MATS requirements have co-benefits that will notably reduce SO_2 emissions.

Pace Global's emission allowance price projections assume that CAIR remains in place through 2016 and then transitions to a revised transport rule market after this time. All transport rule markets are projected to be higher long-term due to more stringent emission caps relative to CAIR. Beyond 2020, allowance markets moderate due to additional coal plant retirements driven primarily by carbon regulation for existing generators. The reference case for these forecasts is presented in Figure 4 below.

Figure 4: Reference Case NO_x and SO_2 Prices (2013$/short ton)



Source: Pace Global.

RENEWABLE ENERGY STANDARDS

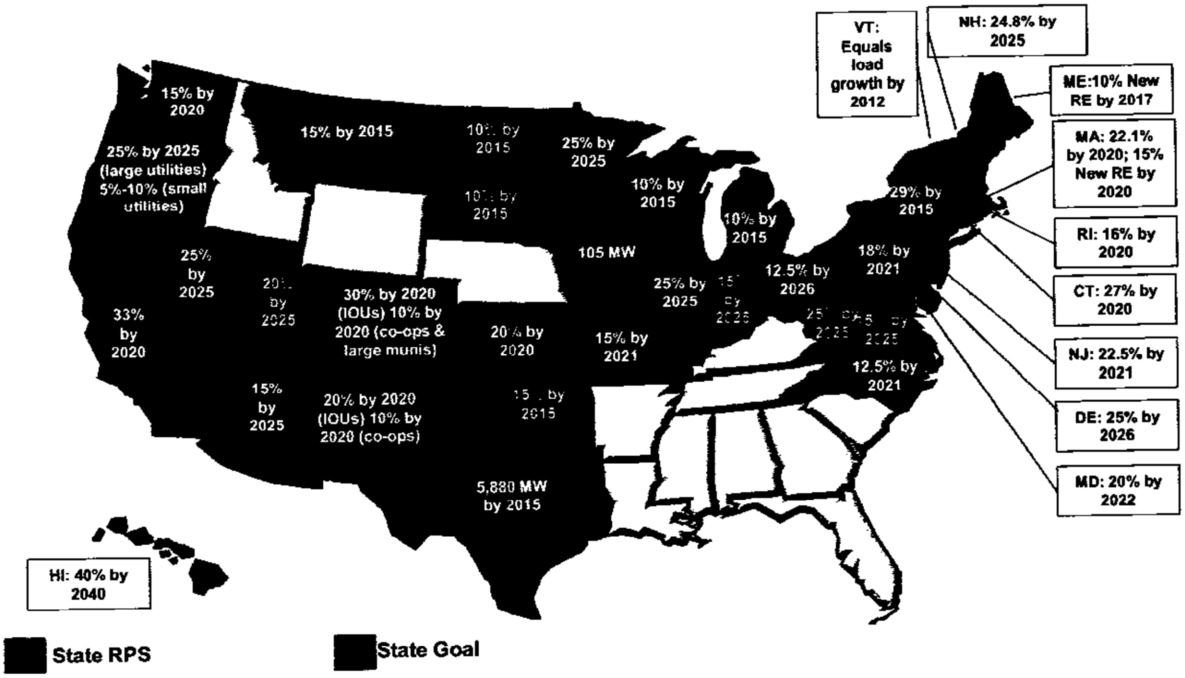
Renewable Portfolio Standards (RPS), also referred to as Renewable Electricity Standards (RES) or Alternative Energy Portfolio Standards (AEPS), are regulated programs placing an obligation on electricity suppliers that a certain percentage of their electricity sold be derived from alternative or renewable energy resources. At this time, 30 states and the District of Columbia have enacted mandatory state-level RPS requirements. A summary of all current state-level RPS is shown in Figure 5 below. In Pace Global's development of regional power market assessments, RPS rules dictate expansion options and economics.

Delaware RPS and REC Drivers

Market pricing for Delaware standard tier compliance RECs have generally trended with or close to the price levels for the collective PJM Tier I / Class I markets, including states like New Jersey and Pennsylvania. The reported pricing for over the counter transactions of RECs eligible for compliance in PJM state Tier I/Class I programs has risen in the past few years. In 2011, these instruments were transacting below \$2/mWh and since then have risen to current levels around \$15/mWh, peaking at \$18/mWh in early 2014. Price increases can largely be attributed to the growing REC demand due to accelerating RPS requirements as well as diminished volumes of banked RECs in the region. Going forward, Pace Global sees additional upward pressure on PJM RECs as state RPS requirements continue to increase sharply through the early 2020s and beyond, and due to the uncertainty of the availability of the production tax credit (PTC). The PTC to date has incented new renewable builds and helped to offset the cost. The absence or reduction of this federal incentive that the renewable industry, particularly wind, has come to rely on would place upward pressure on REC prices as the instrument to account for the cost differential between traditional generation and renewable generation.

The Delaware RPS solar carve out is adequately supplied at this time with enough solar PV installations in the state to meet current requirements, accounting for the 3 year banking provision permitted under the state rule. The RPS requirement for solar (as with standard Tier requirements) increases significantly over the next 10 years which will require that significant incremental capacity be built to comply. The market is expected to require additional solar installations as of the 2018-2020 time frame which is expected to drive prices up. The recent declines in installed solar costs and efficiencies gained by the market over the past few years will help to moderate prices, however, from historic high levels seen at the onset of the Delaware solar market (over \$200/mWh). Prices are expected to settle to a range between \$100 and \$200/mWh for Delaware SRECs until the state requirement peaks in the mid 2020's. Pace Global assumes that the 30% investment tax credit applicable to solar PV installations expires at the end of 2016 per the existing legislation.

Figure 5: **State-level RPS Summary**



Source: State laws/rules and Pace Global analysis.

Section VIII. Renewable Energy Resources

As part of REPSA, the State of Delaware requires that Delmarva Power purchase an increasing amount of RECs from qualified renewable energy sources through 2025. Compliance with this requirement over the IRP Planning Period is an important focus of the 2014 IRP.

To demonstrate compliance with REPSA, each year Delmarva Power must provide to the State documentation that RECs meeting the annual requirement have been retired. In general, one REC is created for every mWh generated by an eligible renewable energy resource. There is also a requirement for a minimum percentage of RECs to be generated from solar photovoltaic resources. For simplicity, RECs generated by solar facilities are often referred to as "SRECs". Table 1 below shows the minimum percentage of Delmarva Power customer's annual energy supply that must be supplied from renewable sources.[28] The percentages shown in Table 1 below can be applied to Delmarva Power's forecasted annual RPS eligible mWh sales to determine Delmarva Power's expected annual quantity of RECs and SRECs to ensure RPS compliance.

Table 1

Delaware Eligible Renewable Energy Requirements

Compliance Year	Minimum Cumulative % from Eligible Resources	Minimum Cumulative % from Solar Resources
2015/16	13.0%	1.00%
2016/17	14.5%	1.25%
2017/18	16.0%	1.50%
2018/19	17.5%	1.75%
2019/20	19.0%	2.00%
2020/21	20.0%	2.25%
2021/22	21.0%	2.50%
2022/23	22.0%	2.75%
2023/24	23.0%	3.00%
2024/25	24.0%	3.25%

[28] 26 *Del. C.* §351, et. seq.

As indicated in Table 1, in 2015/16, the first year of the 2014 IRP Planning Period, Delmarva Power is required to procure 13% of its supply requirements from renewable resources, including at least 1% from solar resources. By planning year 2024/25, the percentage increases to 24% for all qualifying resources, with at least 3.25% from solar resources. The percentages shown in Table 1 can be applied to the Reference Case mWh forecast for all Delmarva Power distribution customers adjusted for the following:

1.) large industrial customers that have chosen (as permitted by law) to not participate in the Delaware RPS; and

2.) REC requirements for customers whose RPS requirements are met by their third-party supplier through existing contracts (phased out as Delmarva Power transitions to meeting the REC requirements of all distribution customers).

The forecast REC requirements for all distribution customers showing the expected RECs needed for RPS compliance, by year, for both solar and non-solar eligible resources, are shown in Table 2 below.

Table 2

REC and SREC Expected Annual Requirements

Compliance Year	RPS Load Obligation (mWh)	Non-Solar Requirement (RECs)	Solar REC Carve-Out (SRECs)
2015/16	6,812,559	817,508	68,125
2016/17	6,813,808	902,830	85,172
2017/18	6,764,202	980,809	101,463
2018/19	6,695,498	1,054,541	117,171
2019/20	6,633,267	1,127,656	132,665
2020/21	6,578,701	1,167,720	148,020
2021/22	6,536,520	1,209,257	163,412
2022/23	6,500,649	1,251,376	178,767
2023/24	6,460,427	1,292,086	193,812
2024/25	6,431,580	1,334,553	209,026

The forecasted REC and SREC requirements shown in Table 2 above are equal to the eligible distribution customer mWh forecast multiplied by the appropriate percentage from Table 1. For the non-solar requirement (REC) calculation the percentage used is the minimum cumulative percentage less the solar carve-out percentage. The results shown in Table 2 will change depending on the load forecast and assumptions used regarding the level of energy efficiency and conservation achieved.

As explained in more detail below, Delmarva Power anticipates securing RECs and SRECs in sufficient quantity to maintain compliance with the REPSA requirements.

A. Contracted Resources

As a result of REPSA, and as approved by the Commission, Delmarva Power has already contracted for a portfolio of wind and solar resources to meet the renewable energy requirements for eligible distribution customers. The specific resources are described below:

1. AES Armenia Mountain: This 100 mW [nameplate capacity] wind project is located in North Central Pennsylvania. Delmarva Power has entered into a 15-year power purchase agreement (PPA) with AES to purchase up to half of the wind energy and RECs from this project. The wind farm became operational and contract purchases began in December 2009.

2. Dover Sun Park: Delmarva Power entered into a 20 year contract to purchase 70% of the SRECs created by the 10 mW [nameplate capacity] Solar Park constructed in Dover by White Oak Solar Energy, LLC, an affiliate of LS Power. The Dover Sun Park is one of the largest solar installations in the Mid-Atlantic region and became commercially operational during the summer of 2011. Accompanying this contract, Delmarva Power signed an agreement with the SEU which allows the SEU to purchase a portion of the SRECs generated by the Sun Park during its first two years of operation for the purpose of banking excess SRECs. Under the terms of the SEU/Delmarva Power agreement, the SEU will return the banked SRECs to Delmarva Power in later years when the RPS solar requirements are greater.

3. Gestamp Roth Rock: Delmarva Power has entered into a PPA with Gestamp to provide RECs and energy from a 40 mW wind farm located in Western Maryland [nameplate capacity]. The wind farm became operational and contract purchases began in August 2011.

4. Gamesa Chestnut Flats: Delmarva Power entered into a PPA with Gamesa to provide RECs and energy from a 38 mW wind project located in Central Pennsylvania. The wind farm became operational and contract purchases began in December 2011.

5. Delaware SREC Procurement Programs: To date, Delmarva Power has secured SRECs under three separate Commission approved programs: the SREC Procurement Pilot Program, the 2013 SREC Procurement Program, and the 2014 SREC Procurement Program. For each of these Programs, the SEU conducted a competitive solicitation to award 20 year contracts for the purchase of SRECs from customer sited facilities located in Delaware. Delmarva Power purchases the SRECs acquired under the program from the SEU. The results for each Program solicitation are shown below:

a. <u>SREC Procurement Pilot Program</u>: The Pilot program resulted in 165 contracts from Delaware-sited solar systems totaling approximately 8.5 mW of capacity.

b. <u>2013 SREC Procurement Program</u>: The 2013 SREC Program resulted in awards for 385 projects for the SRECs produced by 5.5 mW of solar systems.

c. <u>2014 SREC Procurement Program:</u> The 2014 SREC Program resulted in awards for approximately 295 projects for the SRECs produced by an additional 5.5 mW of solar systems.

d. <u>Washington Gas Energy Services (WGES):</u> As part of the RPS transition process in 2010 whereby Delmarva became the exclusive RPS provider for all distribution customers, Delmarva entered into a contract to purchase SRECs from two solar facilities totaling 1.8 mW owned by Washington Gas Energy Services with contract terms similar to those contracts awarded under the SREC Procurement Pilot Program. This contract was approved by the Commission per Order No. 8396, dated June 18, 2013.

The five renewable energy projects/programs outlined here represent a total of 128 mW of wind generation and nearly 30 mW of solar generation resources. This diverse portfolio of renewable energy resources establishes a strong foundation for Delmarva Power's compliance with the Delaware RPS requirements. Over the period 2015-2024, these projects will create a supply of RECs and SRECs that will help Delmarva Power meet its RPS compliance obligations. Table 3 below shows the projected REC and SREC supply from Delmarva Power's contracted renewable resources over the IRP Planning Period:

Table 3

Projection of RECs Created by Existing Contracts

Compliance Year	AES Armenia Wind (RECs)	Gestamp - Roth Rock (RECs)	Gamesa - Chestnut Flats (RECs)	Dover Sun Park (SRECs)	SREC Procurement Programs
2015/16	132,276	105,821	100,530	17,479	32,897
2016/17	132,276	105,821	100,530	18,511	38,763
2017/18	132,276	105,821	100,530	13,493	38,569
2018/19	132,276	105,821	100,530	13,426	38,376
2019/20	132,276	105,821	100,530	13,359	38,184
2020/21	132,276	105,821	100,530	13,292	37,993
2021/22	132,276	105,821	100,530	13,225	37,803
2022/23	132,276	105,821	100,530	13,159	37,614
2023/24	132,276	105,821	100,530	13,093	37,426
2024/25	132,276	105,821	100,530	13,028	37,239

Table 4 below shows how Delmarva Power's supply of RECs and SRECs obtained from contracted renewable resources are currently expected to match up with the projected RPS requirements over the IRP Planning Period.

Table 4

Contracted Resources Position vs. Projected REPSA Requirement

Compliance Year	Non Solar REC Requirement	Contract Wind Resources	Net Position RECs	Solar SREC Requirement	Solar Contract Resources	Net Position SRECs
2015/16	817,508	338,627	-478,881	68,125	50,376	-17,749
2016/17	902,830	338,627	-564,204	85,172	57,274	-27,898
2017/18	980,809	338,627	-642,183	101,463	52,062	-49,401
2018/19	1,054,541	338,627	-715,915	117,171	51,802	-65,369
2019/20	1,127,656	338,627	-789,029	132,665	51,543	-81,122
2020/21	1,167,720	338,627	-829,094	148,020	51,285	-96,735
2021/22	1,209,257	338,627	-870,631	163,412	51,029	-112,383
2022/23	1,251,376	338,627	-912,749	178,767	50,774	-127,993
2023/24	1,292,086	338,627	-953,460	193,812	50,520	-143,292
2024/25	1,334,553	338,627	-995,927	209,026	50,267	-158,759

As shown in Table 4 above, and based on existing contracted resources alone, Delmarva Power's contracted resources do not meet projected requirements for both RECs and SRECs for the IRP Planning Period. However, as discussed in the next Section, additional amendments to REPSA created a provision that allows for the output from qualified fuel cells manufactured and installed in Delaware to offset part of Delmarva Power's RPS obligations. As discussed in more

detail below the output from a Qualified Fuel Cell Provider can be used to help offset both solar and non-solar RPS requirements, as needed.

B. Qualified Fuel Cell Provider

In July 2011, the Governor of the State of Delaware signed legislation establishing that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider" or "QFCP") is an eligible resource for RECs under REPSA.[29] The legislation further required that the Commission adopt a tariff under which Delmarva Power would act as the agent for the QFCP to collect payments from its customers and disburse the amounts collected to a QFCP that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility. The payments from customers would be offset by the market revenues received by the QFCP from selling capacity and energy into the wholesale market netted against its cost of fuel. The legislation also provided for a reduction in Delmarva Power's REC and SREC requirements based upon the actual energy output of the 30-megawatt generation facility. In October 2011, pursuant to Order No. 8062, the Commission approved the tariff submitted by Delmarva Power in response to the legislation.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as the QFCP. Bloom Energy has constructed fuel cell generation facilities at two locations in Delaware. The first site, a 3 mW fuel cell facility at Delmarva Power's Brookside substation, went into operation in June, 2012. The second site, a 27 mW facility located near Delmarva Power's Red Lion Substation, became fully operational in November 2013.

The amendments to REPSA provide that each mWh produced by a QFCP allow Delmarva Power to offset its RPS obligations. Essentially, the output of the Bloom Energy facilities, as a QFCP Project, will reduce the non-solar REC and/or SREC requirements that would otherwise be needed to satisfy REPSA.

The original legislation provided that the output from QFCPs could be used to offset either one REC or 1/6 of a SREC for each mWh generated by the fuel cell. However, during the Commission hearings to approve the QFCP tariff, DNREC testified that an additional multiplier of 2 would be applied to the RECs created by the QFCP. Consequently, the output of the QFCP can be used to offset 2 RECs or 1/6 of a SREC. For ease of presentation in this document, these offsets are expressed as equivalent RECs ("ERECS") and equivalent SRECS ("ESRECS"). Delmarva allocates the QFCP offsets between RECs and SRECs for RPS compliance in a manner to be most cost-effective for customers. Given the current offset structure and projected market prices for

[29] 26 *Del. C.* §352, et. seq.

RECs and SRECs, customers will be better off using all of the QFCP offsets as ERECs. Table 5 below shows the projected amount of the non-solar REC and SREC offsets expected to be created from the QFCP that will help offset Delmarva Power's REPSA requirements.

Table 5
Qualified Fuel Cell Provider
<u>Non Solar and Solar REC Offsets</u>

Compliance Year	Projected QFCP Generation (MWh)	EREC Offsets	SREC Offsets
2015/16	228,636	457,272	0
2016/17	228,636	457,272	0
2017/18	228,636	457,272	0
2018/19	228,636	457,272	0
2019/20	228,636	457,272	0
2020/21	228,636	457,272	0
2021/22	228,636	457,272	0
2022/23	228,636	457,272	0
2023/24	228,636	457,272	0
2024/25	228,636	457,272	0

Tables 6 and 7 below indicate Delmarva Power's projected net position adjusted to reflect the expected impact of the QFCP on Delmarva Power's RPS obligations. For both Tables, a negative net position indicates that Delmarva Power is "short" or will need to purchase more RECs (or SRECs) if projections are accurate. A positive net position indicates that additional RECs are available to be "banked" and used in a future year.

Table 6

QFCP Impact on Delmarva Power's Projected Net Solar Position

Compliance Year	SREC Requirement	QFCP ESRECs	Contracted Resources	Net Position
2015/16	68,125	0	50,376	-17,749
2016/17	85,172	0	57,274	-27,898
2017/18	101,463	0	52,062	-49,401
2018/19	117,171	0	51,802	-65,369
2019/20	132,665	0	51,543	-81,122
2020/21	148,020	0	51,285	-96,735
2021/22	163,412	0	51,029	-112,383
2022/23	178,767	0	50,774	-127,993
2023/24	193,812	0	50,520	-143,292
2024/25	209,026	0	50,267	-158,759

Table 7

QFCP Impact on Delmarva Power's Projected Net RPS Position

Compliance Year	REC Requirement	QFCP ERECs	Contracted Resources	Net Position
2015/16	817,508	457,272	338,627	-21,609
2016/17	902,830	457,272	338,627	-106,932
2017/18	980,809	457,272	338,627	-184,911
2018/19	1,054,541	457,272	338,627	-258,643
2019/20	1,127,656	457,272	338,627	-331,757
2020/21	1,167,720	457,272	338,627	-371,822
2021/22	1,209,257	457,272	338,627	-413,359
2022/23	1,251,376	457,272	338,627	-455,477
2023/24	1,292,086	457,272	338,627	-496,188
2024/25	1,334,553	457,272	338,627	-538,655

C. Incremental RPS Requirements

As indicated in Tables 6 and 7 above, even after the QFCP RPS offsets are taken into account, Delmarva Power projects that it will need RECs and SRECs in excess of currently contracted supply to meet RPS obligations from the beginning of the IRP Planning Period. As mentioned earlier, both RECs and SRECs can be purchased from the spot market to satisfy these requirements. Given the relatively low spot market prices currently available, Delmarva Power anticipates including a significant level of spot market purchases as part of its renewable supply portfolio.

The Renewable Energy Taskforce has recommended that the SREC Procurement Programs be extended into 2015 and Delmarva Power is preparing a filing to the Commission which requests approval for such Program. Since the 2014 SREC program was undersubscribed, Delmarva Power recommends that if the 2015 SREC program is also undersubscribed, or if SREC contract prices continue to escalate, that the Renewable Energy Task Force consider alternative options for the supply of Delmarva Power's solar RPS requirements.

D. RPS Compliance Costs

The following tables present the projected costs of RPS compliance given Delmarva Power's contracted resources, and the forecast with respect to spot market prices. However, as subsequent material appearing in the Section under the heading of "Non-price Impacts of RPS Compliance" shows, there may be human health benefits associated with the improvement in air quality that may be quantifiable and attributable to the implementation of the Delaware RPS.

Table 8 below represents the projected cost for Delmarva Power to meet the Solar RPS requirements. The cost of solar compliance is projected to increase from approximately $7.7 million in compliance year 2015/16, to $32.7 million in compliance year 2023/24.

Table 8
Projection of the Cost to Comply with the RPS Solar Requirement

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Forcasted Load Obligation GWh	6,813	6,814	6,764	6,695	6,633	6,579	6,537	6,501	6,460	6,432
Projected SRECs by Source										
Dover SunPark	17,479	18,511	13,493	13,426	13,359	13,292	13,225	13,159	13,093	13,028
SREC Financing Pilot Program	30,639	36,516	36,333	36,152	35,971	35,791	35,612	35,434	35,257	35,080
QFCP Offsets	0	0	0	0	0	0	0	0	0	0
Spot-Solar	17,749	27,898	49,401	65,369	81,122	96,735	112,383	127,993	143,292	158,759
Total SRECs	65,867	82,925	99,227	114,946	130,452	145,818	161,221	176,587	191,643	206,867
SREC Cost ($1000s)										
Dover SunPark	$3,178	$3,366	$2,453	$2,441	$2,429	$2,417	$2,405	$2,393	$2,381	$2,369
SREC Financing Pilot Program	$3,423	$3,786	$3,770	$3,755	$3,740	$3,672	$2,845	$2,039	$2,033	$2,023
QFCP Offsets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Spot-Solar	$1,108	$2,502	$5,822	$9,173	$12,671	$17,013	$21,853	$26,292	$28,269	$27,575
Total Solar Compliance Costs ($1000s)	$7,709	$9,654	$12,045	$15,369	$18,839	$23,102	$27,102	$30,723	$32,682	$31,966

Table 9 below presents the projected cost to comply with the total RPS requirements. Projected costs increase steadily across the IRP Planning Period from $56.3 million for compliance year 2015/16, to $86.1 million for compliance year 2023/24.

Table 9
Projection of the Total Cost to Comply with the RPS Requirements

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Projected REC by Source										
Solar Supply	65,867	82,925	99,227	114,946	130,452	145,818	161,221	176,587	191,643	206,867
Wind Contracts	338,627	338,627	338,627	338,627	338,627	338,627	338,627	338,627	338,627	338,627
QFCP Offsets	457,272	457,272	457,272	457,272	457,272	457,272	457,272	457,272	457,272	457,272
Spot-REC	21,609	106,932	184,911	258,643	331,757	371,822	413,359	455,477	496,188	538,655
Total RECs	883,374	985,755	1,080,037	1,169,488	1,258,107	1,313,538	1,370,478	1,427,962	1,483,729	1,541,420
REC Costs ($1000s)										
Solar Supply	$7,709	$9,654	$12,045	$15,369	$18,839	$23,102	$27,102	$30,723	$32,682	$31,966
Wind Contract RECs	$11,428	$11,423	$11,162	$10,596	$9,361	$7,081	$6,683	$6,366	$6,511	$8,127
Wind Contract Net Energy Cost	$4,438	$3,301	$3,296	$3,035	$2,468	$1,234	-$1,046	-$1,444	-$1,761	-$1,616
QFCP Offsets	$32,317	$31,157	$31,928	$31,089	$32,838	$32,146	$31,284	$31,385	$31,247	$31,401
Spot-REC	$417	$2,591	$5,378	$8,381	$11,526	$13,568	$15,480	$16,884	$17,445	$16,180
Total RPS Compliance Costs ($1000s)	$56,308	$58,125	$63,808	$68,469	$75,033	$77,131	$79,503	$83,914	$86,124	$86,058

E. Impact of RPS Compliance

As part of the settlement reached in Docket No 10-2, approved by the Commission in Order No. 8083 dated January 10, 2012, Delmarva Power agreed to estimate the impact of compliance with the Delaware RPS on customer bills as part of the 2012 IRP. As described above, Delmarva Power is employing a three-fold renewable resource compliance plan. First, Delmarva Power has developed a portfolio of renewable resources that includes a mixture of long-term contracts for both wind and solar resources. Second, Delmarva Power is able to use the REC and SREC offsets created by the QFCP to help meet its RPS obligations. The third and final piece of the renewables compliance plan is to purchase RECs and SRECs from the spot market, as needed, to ensure that the annual compliance requirements are met. In this Section of the IRP, Delmarva Power provides estimates of the annual impact, over the IRP Planning Period for each of these three components of RPS compliance on customer bills, for both non-solar and solar resources.

Table 10 below provides a summary of the estimated impact of RPS compliance (including the QFCP) on a typical monthly average Residential customer bill of 1000 kWh for the period June 2015 – May 2025.

Table 10
Impact of RPS compliance on Average Residential Customer Bill (1000 kWh/Month)
(Confidential Material Omitted)

Compliance Year	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025
Avg. Residential Customer Bill (1000 kWh/Month)										
Supply				$83.99	$91.24	$96.86	$98.22	$104.10	$104.11	$102.39
Transmission	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10
Distribution	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80
RPS (Includes QFCP)	$8.27	$8.53	$9.43	$10.23	$11.31	$11.72	$12.16	$12.91	$13.33	$13.38
Total				**$149.12**	**$157.45**	**$163.48**	**$165.28**	**$171.90**	**$172.34**	**$170.67**
Solar Compliance Impact on Typical Customer Bill										
SREC Cost	$1.13	$1.42	$1.78	$2.30	$2.84	$3.51	$4.15	$4.73	$5.06	$4.97
SREC % Impact				1.54%	1.80%	2.15%	2.51%	2.75%	2.94%	2.91%
RPS Compliance Impact on Typical Customer Bill										
Total RPS Cost	$8.27	$8.53	$9.43	$10.23	$11.31	$11.72	$12.16	$12.91	$13.33	$13.38
RPS % Impact				6.86%	7.18%	7.17%	7.36%	7.51%	7.74%	7.84%

Note: In Table 10 Transmission and Distribution costs are held constant.

In evaluating the results of Table 10, it is important to keep the following in mind. First, DNREC is in the process of finalizing the regulations for determining the methods for calculating costs related to RPS compliance under 26 *Del. C.* §354 (i) and (j). Because these regulations are not final, they were not used in preparing Table 10. Second, the results in Table 10 are based upon assumptions embedded in the IRP Reference Case. As stated previously, the 2014 IRP does not embed any changes relative to EPA proposed Rule

111(d), PJM proposed capacity market changes or energy efficiency programs that may be implemented in the future through SB 150. Finally, changes in future electricity market prices and customer loads will impact these results.

F. Non-Price Impacts of RPS Compliance

Section 6.1.4 of the regulations governing the preparation of the IRP[30] requires the evaluation of the impact of environmental externalities associated with Delmarva Power's energy procurement plans. Further, REPSA states:

> The General Assembly finds and declares that the benefits of electricity from renewable energy resources accrue to the public at large, and that electric suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the state. These benefits include improved regional and local air quality, improved public health, increased electric supply diversity, increased protection against price volatility and supply disruption, improved transmission and distribution performance, and new economic development opportunities.

As part of the 2012 IRP, using publically available models, Delmarva Power prepared a quantitative evaluation of the impact of changes in Air Quality in the Mid-Atlantic Region and Delaware between 2013 and 2022. The results of this evaluation were presented in Section IX and Appendix 8 of the 2012 IRP. In brief, these results, obtained using publically available analysis tools, quantify the human health benefits resulting from improvements in air quality over the period 2013 – 2022, in the range of $980 million to $2.2 billion and $13 to $29 billion, respectively, for Delaware and the Mid-Atlantic Region. These benefits are driven by reductions in air emissions from all sectors of the economy including power generation, industrial production, and transportation. Consequently, the externality analysis provided in Appendix 8 of the 2012 IRP did not directly identify the separate contribution of renewable resources to the overall improvement in human health that are part of Delmarva Power's renewable resource compliance portfolio. Because an analysis of the separate contribution of renewable resources to improving air quality would be expensive and time consuming, Delmarva Power has employed a simpler approach, as described below.

[30] 26 *Del. Admin. C.*§3009 and 3010.

G. Estimated Impact of Renewables on Air Quality

The wind and solar resources that are part of Delmarva Power's renewable portfolio are considered "intermittent" resources. In other words, they supply energy into the electrical grid whenever the wind is blowing and the sun is shining. In terms of PJM generation dispatch, whenever wind and solar resources are producing power, their output is taken into the grid. In general, when wind and solar resources are supplied into the grid, this requires other generation resources that are "dispatchable" to reduce their generation output in order to maintain grid balance and stability. All dispatchable resources, other than nuclear facilities, produce air emissions such as carbon dioxide (CO_2), Sulfur dioxide (SO_2), and Nitrous Oxide (NO_X) at varying rates. Accordingly, when wind and solar resources generate power, other sources reduce their output and related air emissions.

It is difficult to determine with any precision how much CO_2, SO_2, and NO_X are displaced by wind and solar resources because marginal changes in PJM generation emissions are different for each and every hour during the year, and the specific hourly production of intermittent wind and solar resources during a year's time is hard to predict. Consequently, calculating the exact emissions avoided by intermittent resources can be a complex undertaking. Nevertheless, using some simplifying assumptions, average PJM emission rates for CO_2, SO_2, and NO_X can be combined with the expected annual renewable resource generation mWh associated with Delmarva's renewable resource portfolio to obtain *a range* of benefits from the reduction of generation air emission that may be attributable to Delmarva Power's RPS compliance. Based on the implied values of a ton of SO_2, NO_x and CO_2 from the 2012 IRP, evaluation of changes in air quality over 2013 to 2022, the range of emission reductions can then be valued in dollar terms to determine the potential avoided health costs.

The Air Quality analyses presented in Section IX and Appendix 8 of the 2012 IRP estimates the potential range of health benefits from air quality improvement between 2013 and 2022 from all sectors including electric power generation, industry, and transportation. Based on the contribution of electric power generation emissions from the Mid-Atlantic Region, monetized health-related costs in these states is estimated to range from \$36 to \$98 billion (U.S. \$2010) for 2022. The range is based on different epidemiological studies and discount rates (the discount rates account for the time lag between changes in PM2.5 concentration and changes in PM2.5 mortality).

Breaking this down by type of emission and based on the PPTM results, it is estimated that 63% of the overall health cost is attributable to SO_2 emissions, 6% of the overall cost is attributable to NO_x emissions, and 29% of the overall cost is attributable to primary PM2.5 emissions. As reported in the 2012 IRP, the cost per ton for SO_2 and NO_x is estimated to be within the range of \$43,000 – \$110,000 for SO_2, and \$9,500 – \$25,000 for NO_x. Also, as discussed in Appendix 8 of the 2012 IRP, the health cost per ton of CO_2 is estimated to be within the range of $1 to $100 per ton.

Average annual emission rates (tons/mWh) for CO_2, NO_x and SO_2 can be calculated from the Reference Case for PJM resources that create these emissions. This is shown in Table 11 below.

Table 11
PJM Average Emission Rates (ton/mWh)

Compliance Year	CO_2	NO_X	SO_2
2015/2016	0.7718	0.00041	0.00095
2016/2017	0.7396	0.00038	0.00084
2017/2018	0.7193	0.00036	0.00078
2018/2019	0.7226	0.00037	0.00078
2019/2020	0.7445	0.00039	0.00084
2020/2021	0.7668	0.00042	0.00089
2021/2022	0.7606	0.00041	0.00087
2022/2023	0.7535	0.00040	0.00084
2023/2024	0.7422	0.00039	0.00079
2024/2025	0.7354	0.00039	0.00077

The total amount of renewable resource generation mWh enabled by Delmarva Power's renewable portfolio for the period 2013 - 2023 is shown in Table 12 below.

Table 12
Delmarva Power Renewable Resource Portfolio
Total Renewable Generation mWh

Compliance Year	Contracted Resources	Bloom	Spot	Total
2015/2016	389,003	228,636	39,358	656,997
2016/2017	395,900	228,636	134,830	759,366
2017/2018	390,689	228,636	234,312	853,636
2018/2019	390,428	228,636	324,012	943,076
2019/2020	390,169	228,636	412,879	1,031,685
2020/2021	389,912	228,636	468,557	1,087,104
2021/2022	389,655	228,636	525,742	1,144,033
2022/2023	389,400	228,636	583,471	1,201,507
2023/2024	389,146	228,636	639,480	1,257,262
2024/2025	388,894	228,636	697,413	1,314,943

As discussed earlier, when these resources produce power, they displace other resources that would have otherwise created air emissions. Also, although the exact amount of displaced air emissions is difficult to estimate, such estimates can be made using the average emission rates shown in Table 11 above, using some simplifying assumptions. Assuming that the resources in Delmarva Power's renewable portfolio incrementally reduce air emissions at, say, either 50% or 25% of the average PJM emission rate on an annual basis, the following tables show the reduction in air emissions that would otherwise have occurred.

Table 13

Tons of Emissions Avoided by DPL Renewable Portfolio Resources
(assumes 50% of PJM average emission rates avoided)

Compliance Year	CO_2	NO_X	SO_2
2015/2016	165,300	134	312
2016/2017	196,259	143	318
2017/2018	224,789	154	334
2018/2019	258,113	173	369
2019/2020	298,951	201	431
2020/2021	329,130	227	486
2021/2022	348,115	236	499
2022/2023	366,544	243	502
2023/2024	381,727	248	496
2024/2025	399,445	254	503

Table 14

Tons of Emissions Avoided by DPL Renewable Portfolio Resources
(assumes 25% of PJM average emission rates avoided)

Compliance Year	CO_2	NO_X	SO_2
2015/2016	82,650	67	156
2016/2017	98,130	72	159
2017/2018	112,394	77	167
2018/2019	129,057	86	185
2019/2020	149,476	101	215
2020/2021	164,565	113	243
2021/2022	174,058	118	249
2022/2023	183,272	122	251
2023/2024	190,864	124	248
2024/2025	199,723	127	252

These tons of emission reductions can be applied to the dollar value per ton discussed above to provide a range of estimates for the avoided emission costs attributable to Delmarva Power's RPS compliance plan. This is shown in Tables 15 and 16 below which assume that the avoided emissions are valued at the low end of the range for avoided emission costs.

Table 15

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Renewable Compliance
(50% of average PJM emission rate avoided)

Compliance Year	CO_2	NO_X	SO_2	Total
2015/2016	$165,300	$1,271,936	$13,398,183	$14,835,420
2016/2017	$196,259	$1,359,409	$13,660,158	$15,215,827
2017/2018	$224,789	$1,465,225	$14,376,148	$16,066,162
2018/2019	$258,113	$1,642,321	$15,885,089	$17,785,523
2019/2020	$298,951	$1,914,166	$18,526,143	$20,739,260
2020/2021	$329,130	$2,154,771	$20,890,496	$23,374,397
2021/2022	$348,115	$2,237,308	$21,436,236	$24,021,659
2022/2023	$366,544	$2,309,920	$21,577,441	$24,253,905
2023/2024	$381,727	$2,355,211	$21,341,700	$24,078,639
2024/2025	$399,445	$2,409,152	$21,636,446	$24,445,043

Table 16

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Renewable Compliance
(25% of average PJM emission rate avoided)

Compliance Year	CO_2	NO_X	SO_2	Total
2015/2016	$82,650	$635,968	$6,699,092	$7,417,710
2016/2017	$98,130	$679,705	$6,830,079	$7,607,913
2017/2018	$112,394	$732,612	$7,188,074	$8,033,081
2018/2019	$129,057	$821,160	$7,942,545	$8,892,762
2019/2020	$149,476	$957,083	$9,263,071	$10,369,630
2020/2021	$164,565	$1,077,386	$10,445,248	$11,687,199
2021/2022	$174,058	$1,118,654	$10,718,118	$12,010,829
2022/2023	$183,272	$1,154,960	$10,788,720	$12,126,953
2023/2024	$190,864	$1,177,606	$10,670,850	$12,039,319
2024/2025	$199,723	$1,204,576	$10,818,223	$12,222,521

Section IX: Delmarva Power 2014 IRP Reference Case

In preparing the IRP, Delmarva Power develops a "Reference Case" to represent the Company's expected view of the future procurement planning environment for the –IRP Planning Period. The IRP Reference Case provides a structure for the IRP analysis and evaluations, and a point of comparison for varying key assumptions supporting the Reference Case.

The 2014 IRP Reference Case provides a dynamic view of the expected 2015 – 2024 future state of the electric system within Delaware and PJM. The major assumptions underlying the Reference Case discussed in previous sections of this document reflect the current state of the overall electric system at the time the IRP modeling analysis was undertaken.

The Reference Case provided in the 2014 IRP provides a detailed look at the results of the Company's expected future energy procurement practices for the period 2015 – 2024. The key data planning assumptions underlying the view of Delmarva Power's energy future implied by the Reference Case include the following:

1. The Delmarva Power load forecast (described in Section 4 and Appendix 4);
2. Expected Energy and demand response reductions (described in Section 5);
3. PJM approved transmission system upgrades (described in Section 6);
4. The cost and operating characteristics of supply side resource options, and the expected implementation and timing of various environmental regulations affecting power generation (described in Section 7); and
5. Delmarva Power's plan to procure RECs generated by renewable energy resources in sufficient quantities to meet the annual requirements of REPSA (described in Section 8).

The remainder of this section presents detailed information for the IRP Reference Case and the sensitivity analyses for a low natural gas price scenario.

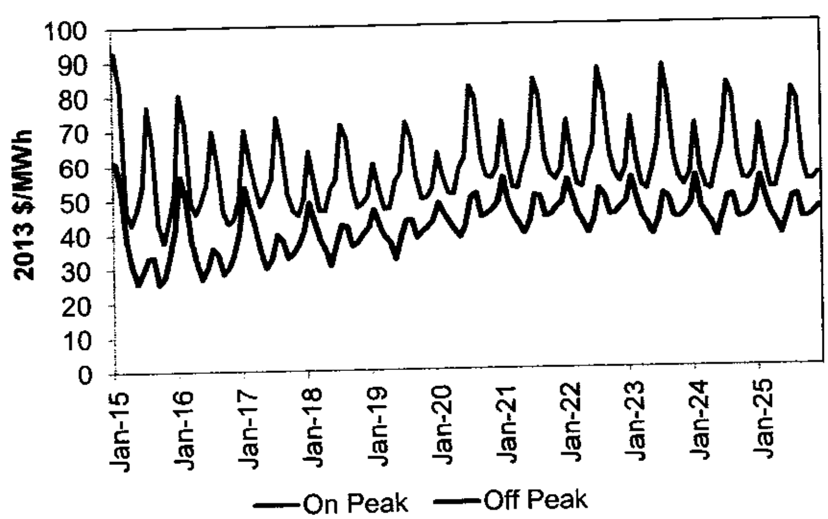
As mentioned earlier, Delmarva Power retained Siemens Industry Inc., for its Pace Global business ("Pace Global") to prepare an independent PJM market assessment to support the 2014 IRP. Covering the period from 2015 to 2025 ("Study Period"), these analyses include Pace Global's market views for energy, capacity, and environmental markets, as well as the key drivers that reflect these views. In its market analysis, Pace Global has employed proprietary tools to simulate the deregulated power generation markets and to project market clearing prices for energy, capacity, RECs and SRECs. All monetary values in this section are denominated in 2013 U.S. Dollars (2013$) unless otherwise noted.

REFERENCE CASE MARKET PRICE PROJECTIONS

Energy Price[31]

Pace Global's reference case PJM market price projections reflect an integrated market assessment that includes inputs for natural gas prices, coal prices, load growth, environmental compliance costs, and capacity additions and retirements. Figure 1 below summarizes the Reference Case energy price projections for the DPL zone within PJM. The high price projections during winter months in the early years are driven by expectations for localized gas price spikes due to high demand and pipeline constraints. Over time, those are expected to relax, but natural gas prices at the Henry Hub and across the PJM footprint are expected to rise overall by the end of the current decade, as a result of increased demand from power generation and exports. Rising gas price expectations and coal retirements throughout PJM contribute to expected increases in power prices over time, especially during the summer peak period.

Figure 1: Reference Case PJM DPL Zone Energy Price Projections



Source: Pace Global.

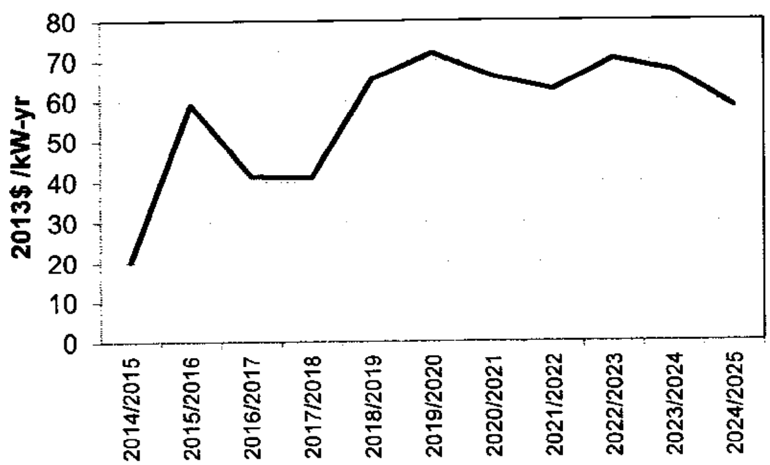
[31] Appendix 6, prepared by Pace Global, provides an overview of PJM electric markets and historical prices.

Capacity Price

Figure 2 below shows Pace Global's capacity price projections for the DPL zone, which also corresponds to projections in the Eastern Mid-Atlantic Area Council ("EMAAC") Locational Deliverability Area ("LDA"), over the Study Period in \$/kW-yr terms for each auction period. Capacity prices through the 2017/2018 period are based on actual PJM Base Residual Auction ("BRA") clearing prices.[32]

Capacity prices for years beyond the auction period are driven by the supply-demand balance (or reserve margin) in the region, the cost of new entry ("CONE"), and the energy revenues that can be realized by plants operating in the market. Pace Global has analyzed the PJM capacity market in an integrated fashion with our energy market projections.

Figure 2: Reference Case DPL Zone Capacity Price Projections



Source: Pace Global.

REC and SREC Price

Pace Global projects renewable energy credit ("REC") and solar renewable energy credit ("SREC") prices for Delaware and the rest of PJM through analysis of current market signals, review of the supply-demand balance for renewable generation, and incorporation of other power market fundamentals. Figure 3 below presents Pace Global's projections for both REC products in the reference case.

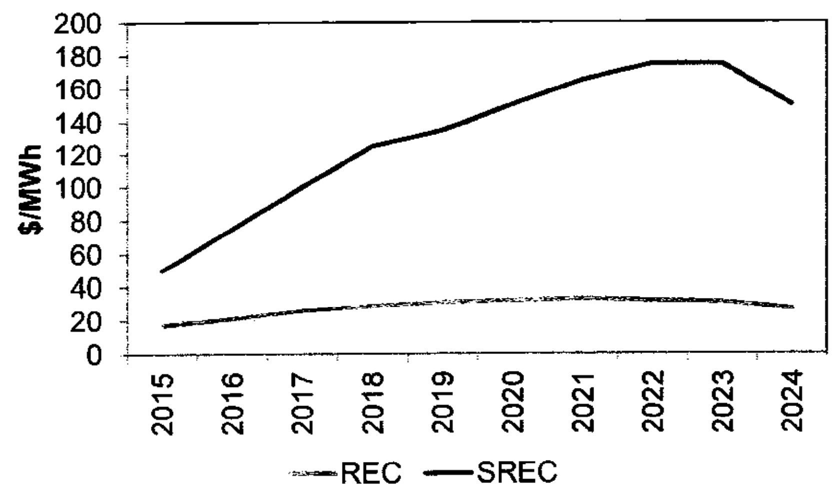
Market pricing for Delaware standard tier compliance RECs have generally trended with or close to the price levels for the collective PJM Tier I / Class I markets, including states like New Jersey and Pennsylvania. The Reported pricing for over the counter transactions

[32] The PJM BRA auction year begins June 1 and ends May 31 of the following year.

of RECs eligible for compliance in PJM state Tier I/Class I programs have risen notably in the past few years. Going forward, Pace Global sees additional upward pressure on PJM RECs as state RPS requirements continue to increase sharply through the early 2020s and beyond, and due to the uncertainty of the availability of the production tax credit (PTC).

The Delaware RPS solar carve out is adequately supplied at this time with enough solar PV installations in the State to meet current requirements, accounting for the 3 year banking provision permitted State law. The RPS requirement for solar (as with standard Tier requirements) increases significantly over the next 10 years, which will require that significant incremental capacity be built to comply. The market is expected to require additional solar installations as of the 2018-2020 time frame, which is expected to drive prices up. The recent declines in installed solar costs and efficiencies gained by the market over the past few years will help to moderate prices, however, from historic high levels seen at the onset of the Delaware solar market (over \$200/mWh). Prices are expected to settle to a range between \$100 and \$200/mWh for Delaware SRECs until the State requirement peaks in the mid 2020's. Pace Global assumes that the 30% investment tax credit applicable to solar PV installations expires at the end of 2016 per the existing legislation.

Figure 3: Reference Case REC and SREC Projections



Source: Pace Global.

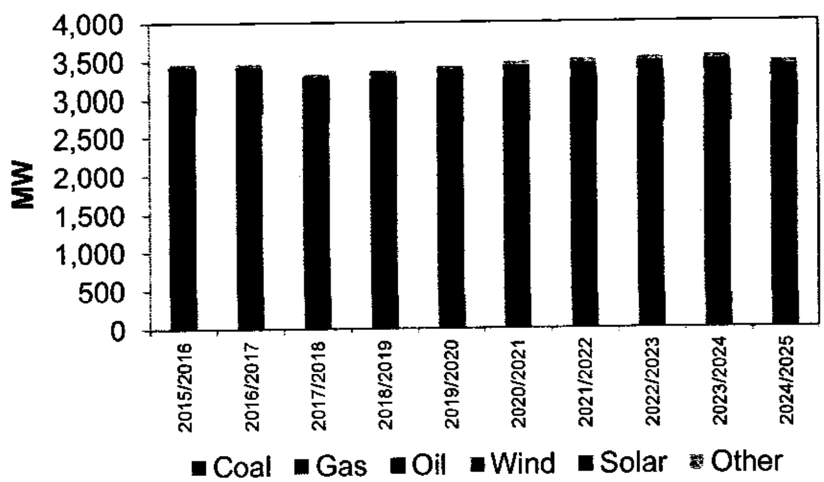
REGIONAL GENERATION, CAPACITY EXPANSION, AND EMISSIONS

Pace Global's integrated power market analysis produces projections for generation over time as well as capacity additions and retirements.

Delaware

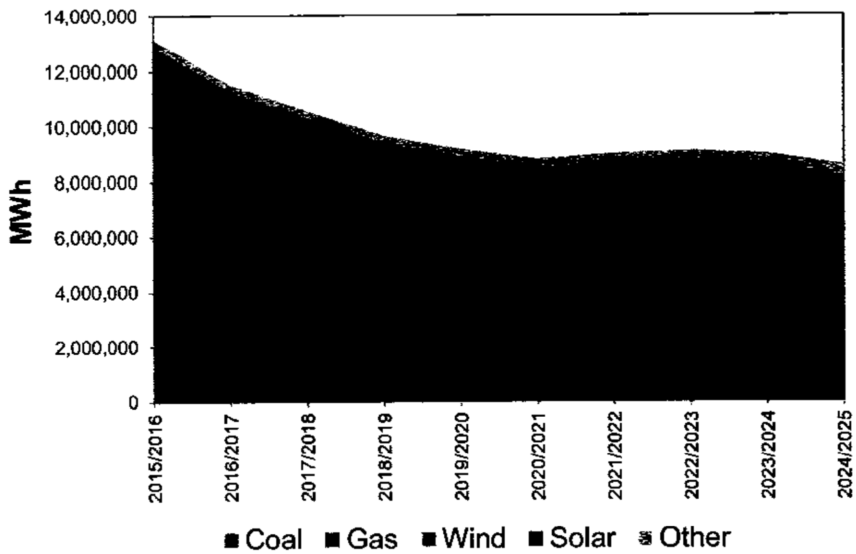
Figure 4 below presents expectations for the installed capacity in the State of Delaware over time, while Figure 5 below summarizes the projected generation by fuel type. In the 2015 time period, the Garrison combined cycle is expected to be online. Beyond that, most capacity changes are expected as a result of wind and solar additions. The generation profile within the State is dominated by natural gas. Total in-state mWh generation is expected to decline over time as a result of increased imports from new, efficient combined cycle capacity in neighboring states that displaces peaking capacity in Delaware. Pace Global's reference case also reports key emissions outputs for CO_2, NOx, and SO_2. Within Delaware, emissions of all pollutants are expected to fall significantly in the next few years. After 2020, when coal generation is projected to recover modestly, slight increases in emissions are projected. Figure 6 below summarizes the emission projections for Delaware over time.

Figure 4: Delaware Installed Capacity over Time (mW)



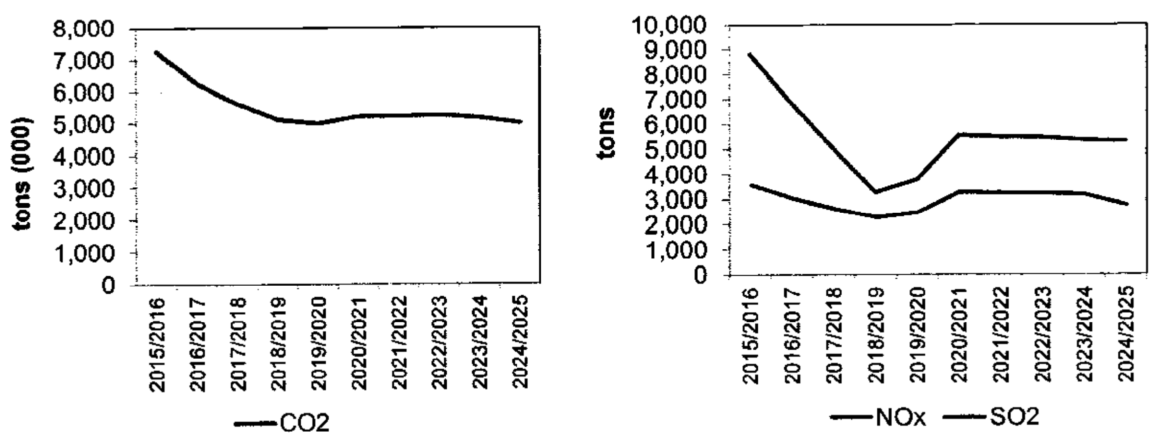
Source: Pace Global.

Figure 5: **Delaware Generation by Fuel Type over Time (mWh)**



Source: Pace Global.

Figure 6: **Delaware Emission Projections over Time**

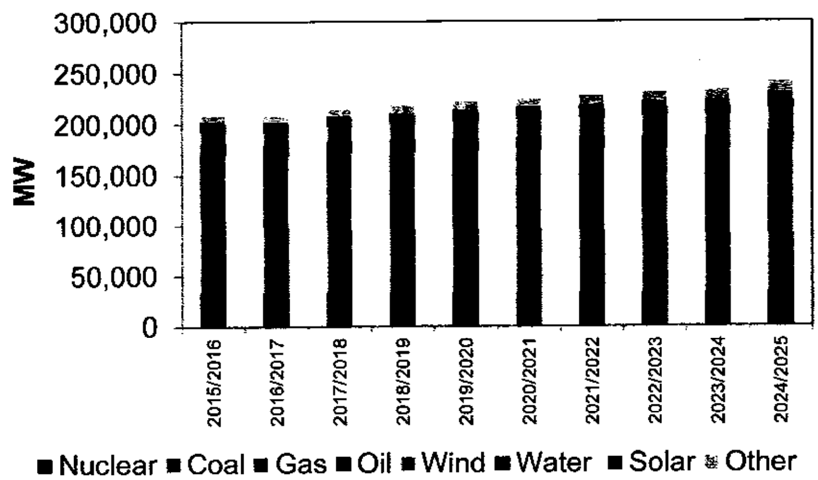


Source: Pace Global.

PJM

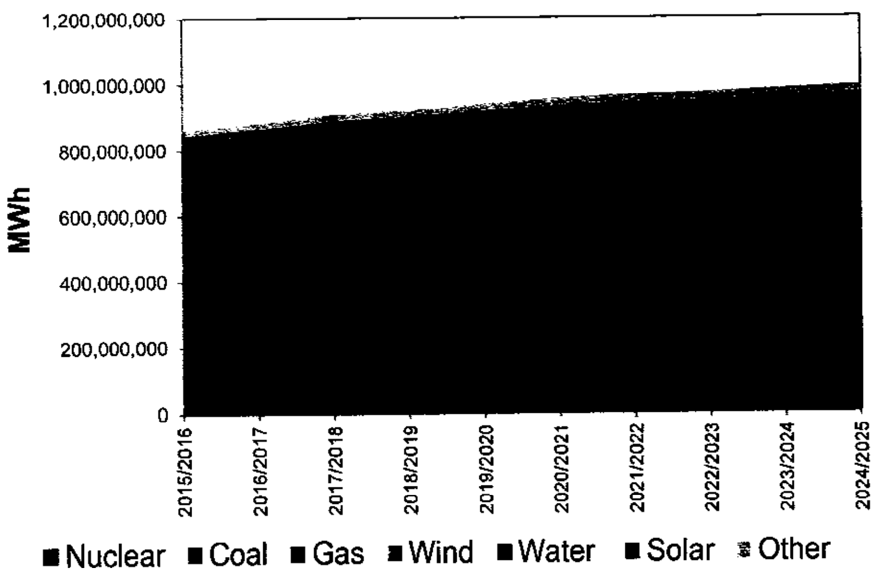
Figure 7 below summarizes the installed capacity projections over time for the entire PJM footprint, while Figure 8 below displays the generation by fuel type. Unlike Delaware, PJM has a large amount of nuclear capacity and generation, which is expected to stay relatively constant over time. Coal capacity is expected to decline by over 12,000 mW in the next few years due to retirements as a result of environmental regulations. Renewable and natural gas-fired capacity is expected to dominate new capacity additions through the Study Period. Although coal capacity is declining, generation is still expected to pick up by the end of the decade due to rising natural gas prices, which make coal dispatch more economic. This increase in generation in the 2020s is expected to lead to emission increases for CO_2, NOx, and SO_2. While declines are expected in the near term as a result of retirements, dispatch economics have the potential to overcome the capacity declines in the reference case over time. Figure 9 below summarizes the projected emissions across all of PJM over time.

Figure 7: PJM Delaware Installed Capacity over Time (mW)



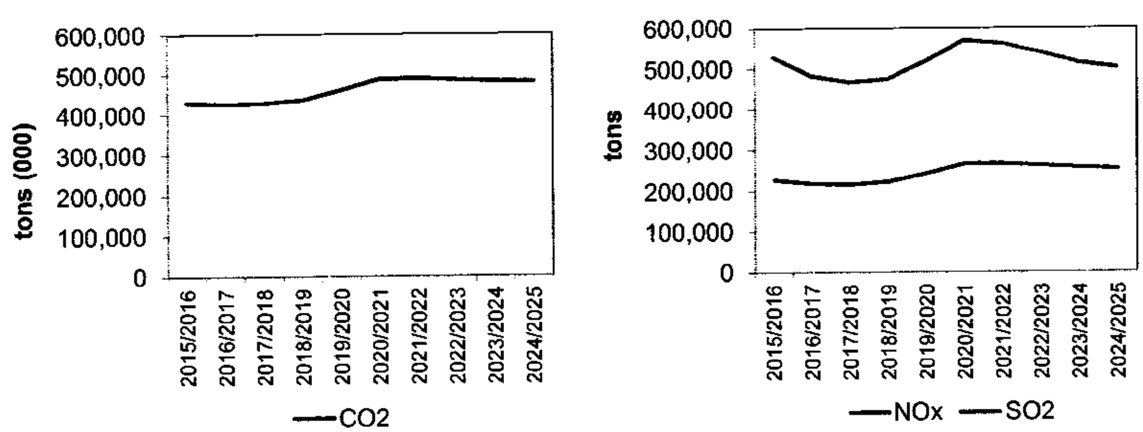
Source: Pace Global.

Figure 84: PJM Generation by Fuel Type over Time (mWh)



Source: Pace Global.

Figure 9: PJM Emission Projections over Time



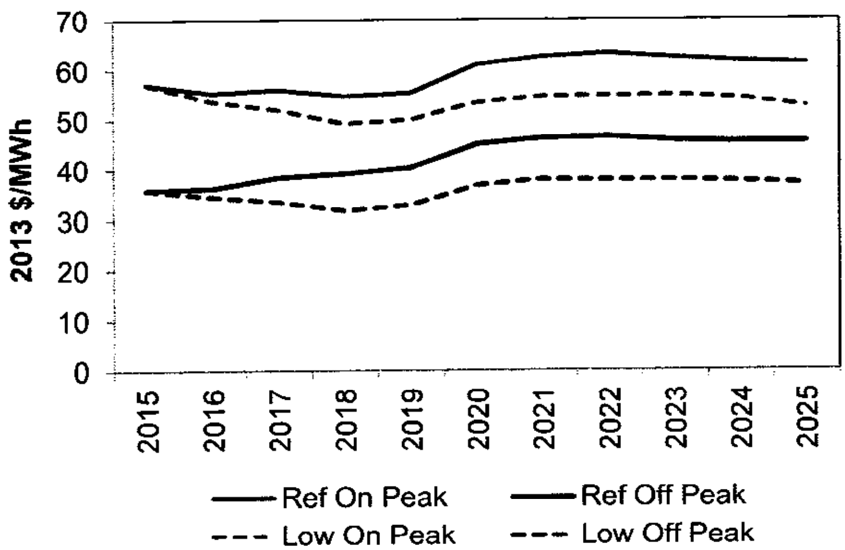
Source: Pace Global.

LOW NATURAL GAS CASE MARKET PRICE PROJECTIONS

Given significant uncertainty associated with the price of natural gas, Pace Global has assessed the risk of lower natural gas prices on the PJM market. This low natural gas price scenario presumes larger production capabilities in the $3-4/MMBtu (Real $) range over the next ten years. Generally speaking, the low natural gas price case has prices around $1/MMBtu lower than those in the Reference Case. Further details on the gas price inputs can be found in the Section on fuel prices.

Figure 10 below summarizes the impacts of the low gas price scenario on projected DPL zone energy prices. As the difference between the two natural gas price projections grows, the average impact on the power prices increases as well, settling at a difference of around $8/mWh in the 2020s.

Exhibit 10: Low Natural Gas Price and Reference Case Energy Projections



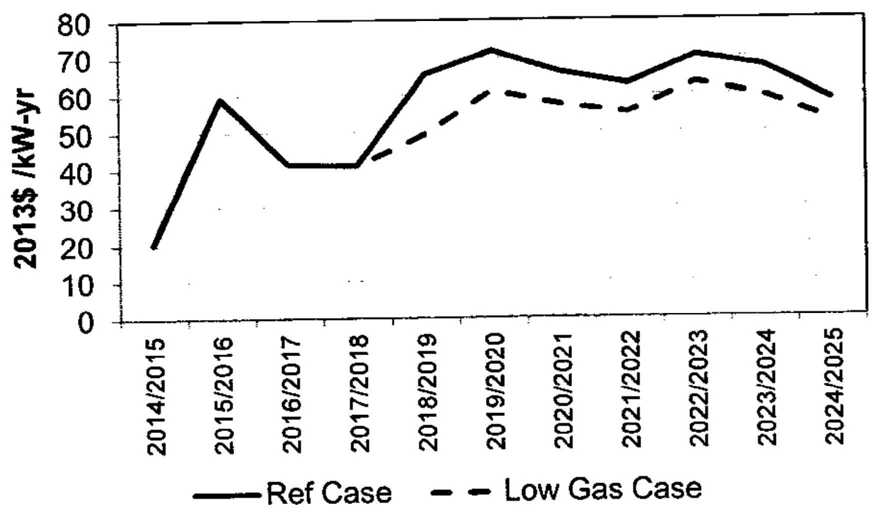
Source: Pace Global.

Beyond the period of cleared PJM capacity auctions, the low natural gas price case also puts downward pressure on expected capacity prices. Under the low gas price regime, new entry in the form of efficient combined cycles is expected to dispatch more, displacing coal capacity and earning higher energy margins. As a result, the capacity payment requirements for these new entrants are expected to be lower. Figure 11 below shows the difference between the capacity prices for the DPL zone across the two cases, indicating that the decline in capacity prices is projected to be about $7-8/kW-yr.

On the other hand, lower power prices are likely to lower the revenues for new renewable resources, causing the prices for RECs to increase in order to compensate new entry. Pace Global's analysis indicates that REC and SREC values are likely to increase by $4-5/mWh in this scenario. This is shown in Figure 12 below.

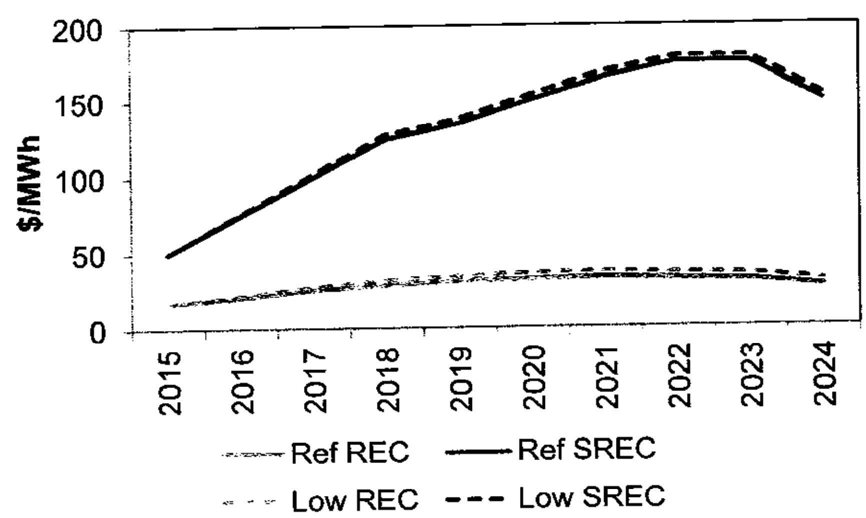
The low natural gas price environment is also expected to lead to lower emissions across PJM, as natural gas capacity displaces coal capacity in the generation dispatch stack. Although some price increases in natural gas are also expected in the low case around 2020, the overall emissions of CO_2, NOx, and SO_2 are projected to be on the order of 20 percent lower than they are in the reference case. This is shown in Figure 13 below.

Figure 11: Low Natural Gas Price and Reference Case Capacity Price Projections



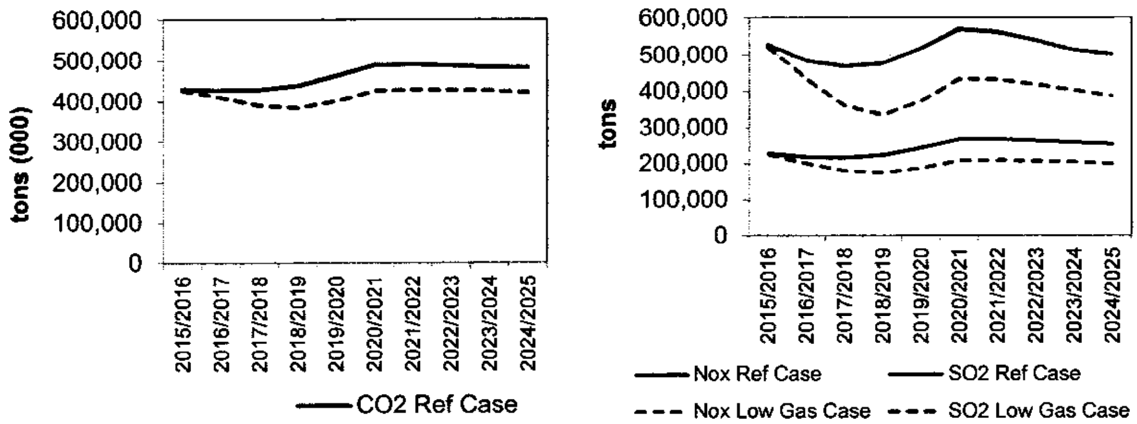
Source: Pace Global.

Figure12: Low Natural Gas Price and Reference Case REC and SREC Projections



Source: Pace Global.

Figure 13: PJM Low Natural Gas Price and Reference Case Emission Projections



Source: Pace Global.

Appendix 1

	IRP Regulation No.	Requirement	IRP Section	Comments
1	General 1.3	In accordance with 26 Del. C. 1007, DPL shall file an IRP on Dec 1, 2006 and on the anniversary date of the first filing date every other year thereafter		The 2014 IRP was filed on Monday, December 1, 2014.
2	General 1.4	The IRP shall be filed in compliance with normal Commission policies and practices		The IRP was filed in accordance with all prevailing Commission rules and procedures.
3	General 1.5	The IRP shall identify the year of filing, the individuals responsible for its preparation and those individuals who shall be available to inquiries during the Commission's review of the plan.	Appendix 2	A listing of the individuals responsible for preparing the 2014 IRP and who will be available for responding to inquiries during the Commission's review of the 2014 IRP are provided in Appendix 2 of the 2014 IRP.
4	General 1.6	Confidential utility documents shall be presented under separate seal.		Confidential documents related to this IRP were presented to the Commission, Staff, DPA and DNREC under separate seal. Due to the timing of the filing of this IRP with the SOS auction process, Delmarva has filed certain pricing information as confidential so as to not bias the auction bids unfavorably. Upon completion of the auction process, this information will be deemed non-confidential by the Company and made available consistent with prevailing SOS guidelines.
5	General 1.8	The utility shall provide whatever detail and commentary necessary to demonstrate that it has met or exceeded the planning requirements as set forth in this regulation. An effort shall be made to ensure that the IRP is clearly stated and can be readily comprehended by the Commission, State Agencies , and other interested parties. The IRP shall include an Executive Summary.	Executive Summary, Appendices 4, 6, and 8	This IRP Regulation Compliance Matrix has been included as Appendix 1 to the IRP. An Executive Summary in the form required by Regulation 3.2.1. is provided in the IRP. Technical information has been set forth in the Appendices in order to keep the text of the IRP clear and straightforward.
6	General 1.9	Compliance with this regulation is a minimum standard for IRP's. The Company needs to exercise its professional judgment based on its systems or customer needs. The Company shall include all information that assists the reader to fully understand the IRP concept and the Company's IRP to meet SOS energy needs.	Executive Summary and Appendices 4,6, and 7.	Delmarva has provided an Executive Summary consistent with IRP Regulations. Most technical materials related to the IRP have been provided in Appendices. Delmarva has attempted to provide all information needed to assist the reader in understanding the IRP in a clear and starightforward manner.
7	General 1.10	This regulation requires the maintenance and retention of supply resource planning data and the reporting of IRP achievements on an annual basis starting in 2009 to the Commission, Governor and General Assembly. The Company shall retain supply resource planning data, consistent with Federal data retention guidelines and make it available for further review as necessary.		Delmarva will retain IRP information consistent with Federal data retention guidelines. Delmarva has reported on the status of the IRP to the Commission, Governor and General Assembly on an annual basis, since 2009, and will submit a new report on or before December 31, 2014.
8	General 1.11	The Company shall submit 8 copies of the IRP to the Commission, 2 copies to the Controller General's office, 2 copies to the Office of Management and Budget, 2 copies to the Division of Public Advocate and 2 copies to DNREC/Energy Office. The Commission may request up to 6 additional copies for review.		DPL submitted 8 copies of the IRP to the Commission, 2 copies to the Controller General's Office, 2 copies to the Office of Management and Budget, 2 copies to the Division of Public Advocate and 2 copies to DNREC on Monday, December 1, 2014.
9	General 1.14	The Company shall make the full IRP, including any appendices or other supporting materials, available to the general public on its web site and shall update these materials on the Company's web site to remain current with all subsequent updates, revisions or other changes made to the IRP.		A copy of the public version of the IRP will be placed on the Company's website after the IRP is filed on December 1, 2014.
10				

11	ral 3.1.1	The IRP shall provide a framework for comparing a comprehensive resource mix of supply and demand-side and Transmission Service resource costs and attributes.	IRP Section 3, 5, 6, and 7.	The IRP uses a detailed and comprehensive planning model (AuroraXMP®) to evaluate the optimal combination of demand and supply side resources within PJM, including Delaware. AuroraXMP uses the most recent PJM Regional Transmission Expansion Plan (RTEP) to characterize the expected future transmission grid. Supply side resources are described in Section 7 and AuroraXMP® is described in Section 3. The RTEP is described in Section 6 and demand side resources are described in Section 5.
12	General 3.1.2	The IRP shall utilize a Resource Portfolio approach in achieving the objectives of the IRP, shall incorporate a Portfolio approach to securing resources and incorporating an analysis of risk versus certainty into the planning process, or absent such a Portfolio approach, the rationale supporting the exclusion.	Executive Summary and IRP Section 9.	The Reference Case of the IRP employs a Resource Portfolio approach to securing supply resources through the competitive Full Requirements Service (FRS) auction and a portfolio of a diverse mix of renewable resources. The IRP describes the effect on price and price stability of electricity supply prices by evaluating a low gas price forecast in comparison to the Reference Case.
13	General 3.1.3	The IRP shall provide for a regulatory, stakeholder, and public input into the development of the IRP in accordance with normal Commission policies and practices.		An IRP Working Group, composed of representatives of Delmarva, Commission Staff, DPA, DNREC, the Caesar Rodney Institute, MAREC and other interested parties met on July 23 to review and discuss key topics related to developing the 2014 IRP. These topics included the estimation of savings from energy efficiencies, Reference Case assumptions, and sensitivity analysis around natural gas prices. Public workshops on the IRP are expected to be scheduled after the 2014 IRP is filed.
14	General 3.1.4	The IRP shall include provisions for the IRP to be modified from time to time to conform with any subsequent legislative or regulatory directives.		The Commission issued Order No 8574 in July, 2014. This Order ratified the IRP filed by Delmarva in December, 2012 and provided guidance for the preparation of the 2014 IRP filing.
15	General 3.2.1	The IRP shall include an executive summary with a short description of the utility, its customers, service territory, current facilities, planning objectives, notable areas of departure in the new IRP from the old, citing specific locations within the IRP where the new aspects shall be found, load forecast, proposed IRP and Implementation Plan.	Executive Summary	An Executive Summary of the IRP with the specific information requested under this regulation is provided in the IRP.
16	General 3.2.2	The IRP shall include Established Plan Objectives in quantitative and qualitative terms by which the IRP achievements may be measured and shall not be biased against any particular option. Measures must be ascribed to each objective. The Company must include a summary of the overall process and models used in developing the IRP.	Executive Summary and Section 3	Plan objectives and measures are described in the Executive Summary of the IRP. Each objective has measures ascribed to them. The major model used in developing the 2014 IRP is AuroraXMP®. This model is used to simulate expected generation expansion and long term wholesale prices and provide information to analyse price stability and power plant air emission levels.
17	General 3.2.3	The IRP shall include a description of the load forecast, the assumptions used or implicit in creating the forecast, the range of forecasts examined and the forecast selected for the filing period and a detailed rationale for such selection.	Section 4 and Appendix 4	The load forecast is described in Section 4 of the IRP. The forecast provides "high" and "low" forecast ranges as compared to the "baseline" forecast. The load forecast documentation is described in Appendix 4.
18	General 3.2.4	The IRP shall include an Integrated Resource Evaluation which shall include a listing of all the options considered to meet the load forecast, identification of those chosen for further evaluation and possible inclusion in the IRP, and a discussion of the rationale for such selections including any key assumptions. The IRP shall include planning information which shall include a ten year planning horizon, starting with the year immediately following the planning year.	Sections 4, 5, 6 and 7.	resource options evaluated by AuroraXMP® model are discussed in Sections 3 and 7 the 2014 IRP. Key assumptions for the Reference Case are provided in Sections 4, 5, 6,and 7 of the IRP. The IRP presents information for the ten year planning period 2015-2024.
19	General 3.2.5	The IRP shall include a Scenario Analysis used to integrate the options into a single resource plan or individual scenarios for further review and analysis to include a listing of the various scenarios considered and any key assumptions.	Executive Summary	The IRP evaluates the potential impact on price and price stability through sensitivity analyses relating to an alternative natural gas price forecast.

20	General 3.2.6	The IRP shall include a description of the process used to develop the proposed IRP, including the assumptions and analysis leading up to the decision and the application of the various criteria as specified in Section 5.0.	Section 3	The process for the development of the IRP is described in Section 3 of the 2014 IRP. Discussions around the IRP process took place with the Working Group on July 23, 2014.
21	General 3.2.7	The IRP shall include an analysis of the risk and sensitivity of the proposed IRP in comparison to the other options that were considered and a contingency plan to meet the Plan Objectives should one of the supply, demand, or transmission options be either delayed or not realized.	Executive Summary	The results of various risk and sensitivity analyses around changes in natural gas prices are described in the Executive Summary.
22	General 3.2.8	The IRP shall include plans for the implementation of the IRP, for no less than 5 years, starting with the year immediately following the filing year.	Executive Summary	Implementation Plans for achieving the planning objectives of the IRP are provided in the Executive Summary.
23				
24	Load Forecast 4.1.1	The Company shall consider a range of load growth forecasts that include both historical data and future estimates.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast is based on historical data and estimates of future DSM activity. More Detailed documentation of the load forecast is provided in Appendix 4.
25	Load Forecast 4.1.2	The Company's load growth forecasts shall include both winter and summer peak demand for Delmarva Delaware load.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes both winter and summer peak demand for Delmarva Delaware Load as shown in Appendix 4.
26	Load Forecast 4.1.2	The Company's load growth forecasts shall include Delmarva Delaware SOS load by customer class.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes a breakdown by customer class.
27	Load Forecast 4.1.3	The Company's load growth forecasts shall include weather adjustments, including consideration of climate change potential.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes a severe weather case. The severe weather case represents a 90/10 scenario, where the degree days used in the equations are at the 90th percentile for both cooling and heating degree days.
28	Load Forecast 4.1.4	The Company's load growth forecasts shall include 5 year historical loads, current year end estimates and 10 year weather adjusted forecasts showing individually and aggregated Delmarva Delaware and Delmarva SOS load, and both Delmarva Delaware and Delmarva Delaware SOS load disaggregated by customer class including both capacity (MW) and energy requirements (MWh).	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes 5 year historical loads as shown in Appendix 4
29	Load Forecast 4.1.5	The Company's load growth forecasts shall include analysis of how existing and forecast Conservation, DR, DSM, Customer sited generation, various economic and demographic factors including the price of electricity will affect the consumption of electric services and how customer choice under Retail Competition may affect future loads.	Section 4 and Appendix 4	Appendix 4 provides detailed documentation of the process of how economic and demographic variables are included in the Load Forecast. Energy conservation measures and DR program impacts are subtracted from the baseline load forecast to derive the Reference Case Forecast.
30	Load Forecast 4.1.6	The Company's load growth forecasts shall include a description of the process the Company used to develop these forecasts. Forecasts should include the probability of occurrence. Within the forecasting modeling descriptions, the Company shall demonstrate how well its model predicted load for the past 5 years.	Section 4 and Appendix 4	DPL's IRP Reference Case load growth forecast includes a description of the process the Company used to develop these forecasts as shown in the DE IRP Demand Forecast Documentation provided as Appendix 4.
31				
32	Resource Portfolio Options 5.1	The Company shall include a description of the overall process and the analytical techniques it used to identify its proposed options. The Company shall not rely exclusively on any particular resource or purchase procurement policy.	Section 3	The IRP process is described in Section 3. Delmarva's Reference Case includes a mix of Full Requirements Service contracts and a diverse mix of renewable resources.
33	Resource Portfolio Options 5.2	The Company shall identify and evaluate all resource options including generation and transmission service, supply contracts, both short and long term procurement DSM, DR, and customer sited generation, even if a particular strategy is not recommended by the Company. The IRP must show an investigation of all reasonable opportunities for a more diverse supply at the lowest reasonable cost including consideration of environmental benefits and externalities. The Company shall also provide any hedging guidelines and shall identify any changes from any existing hedging policy. Cost evaluations shall contain a description of each option and an evaluation that considers the economic and environmental value of the following:	Section 3, 5, 6, 7, 8, and 9.	The IRP considers a full range of transmission, demand side, and supply resources with particular attention to renewable resources and environmental benefits.
34	Resource Portfolio Options 5.2.1	Resources that utilize New or Innovative Base load Technologies;	Section 3	The AuroraXMP® model used in the IRP considers new and innovative base load technologies within the set of resource options evaluated.

35	Resource Portfolio Options 5.2.2	Resources that provide short or long-term environmental benefits to the citizens of Delaware;		Detailed environmental analyses were filed as part of the 2010 and 2012 IRP's and are incoprporated in this IRP by Reference.
36	Resource Portfolio Options 5.2.3	Facilities that have existing fuel and transmission infrastructure;		As part of the 2010 IRP, Delmarva filed a confidential Generation Siting Study in January 2010. This Document remains relevant for the 2014 IRP.
37	Resource Portfolio Options 5.2.4	Facilities that utilize existing brownfield or industrial sites;		As part of the 2010 IRP, Delmarva filed a confidential Generation Siting Study in January 2010. This Document remains relevant for the 2014 IRP.
38	Resource Portfolio Options 5.2.5	Resources that promote Fuel Diversity;	Section 8	Delmarva mamages a portfolio of wind and solar resources.
39	Resource Portfolio Options 5.2.6	Resources or facilities that support or improve reliability; or	Section 6 and 9	The 2014 IRP shows that there are sufficient generation resources to meet the expected load forecast over the IRP planning horizon.
40	Resource Portfolio Options 5.2.7	Resources that support or improve price stability.	Executive Summary	The IRP contains an evaluation of a effects on price and price stability of changing gas prices.
41	Resource Portfolio Options 5.3	Where Transmission Service is identified as a planning option, DPL shall describe the transmission enhancement, the location, and provide PJM's assessment of the impact of the proposed transmission asset when available. The IRP shall reflect the current projects included in PJM's Regional Transmission Plan ("RTEP"). DPL shall file with the Commission any PJM revisions or updates to the RTEP immediately upon receipt.	Executive Summary and Section 6	The IRP includes a description of the transmission investments made since the last IRP and planned transmission investments needed to maintain reliability. All approved RTEP projects are included in the AuroraXMP model.
42	Resource Portfolio Options 5.4	At least 30% of the resource mix shall be acquired through the regional Wholesale Electricity Market via a bid procurement or auction process held by DPL.	Executive Summary and Appendix 5	The discussion of price and price stability in the Executive Summary is based on portfolios with more than 30% acquired through the wholesale market.
43	Resource Portfolio Options 5.5	The Company shall include a discussion of known plans to reduce existing physical, contractual, or service related portfolio resources during the IRP planning period.		The IRP includes all planned retirements at the Indian River generation facility and environmental upgrades to Indian River Unit #4.
44	Resource Portfolio Options 5.6	The Company shall include a detailed description of its energy efficiency activities in accordance with 26 Del. C. DPL Section 1020. The Company shall first consider electricity DR and DSM strategies for meeting base load and load growth needs and cost-effective renewable energy resources before considering traditional fossil fuel-based electric supply service to meet their retail electricity supplier obligations as defined in 26 Del. C. Section 352.	Section 5	The Delaware Public Service Commission approved the implementation of a Dynamic Pricing Program and a Residential Direct Load Control Program in the Fall of 2012. A description of the Company's energy efficiency efforts is provided In Section 5 of the IRP.
45	Resource Portfolio Options 5.7	The Company shall evaluate all technically feasible and cost effective DR improvements. Where non-Company evaluations of DSM and Conservation are available through the Sustainable Energy Utility ("SEU") (or other organization as requested by the Commission), the Company shall summarize the results and actions taken. The Company shall collaborate and may contract with the SEU to provide services to accomplish the SEU's DSM plans. The Company, using its independent best judgment, may recommend in the IRP any DSM program first offered to the SEU but rejected by the SEU. Where DR programs are new, the Company shall summarize the anticipated benefits with respect to load reductions and provide supporting materials to justify the new program.	Section 5	Delmarva Power continues to collaborate with the SEU. A description of on-going and past SEU activities is provided in Section V of the IRP.
46	Resource Portfolio Options 5.8	The Company shall collaborate with the SEU and appropriate State Agencies in its evaluation of Customer Sited Generation resource options. The Company may enter into a contractual relationship with the SEU or other energy service providers to implement a Customer Sited Generation resource option strategy.	Section 5	Under the Solar REC Procurement Programs approved by the Commission, Delmarva has entered into contracts to purchase Solar RECs from the SEU.
47	Resource Portfolio Options 5.9	The Company shall assess the Resource Portfolio options against the set of Plan Objectives and criteria.	Section 3, 5, 6, 8, and 9	The Reference case is evaluated against the major planning criteria and plan objectives.
48				
49	Plan Development 6.1	The Company shall conduct an Integrated Resource Evaluation in formulating its potential plans for supply and demand-side resource scenarios. The Company shall describe the mechanism or process by which the Load Forecast and options have been blended into the various IRP scenarios.	Section 3, 4, 5, and 9	TheAuroraXMP® model provides an integrated planning platform. Expected energy efficiency savings are incorporated into the Reference case load forecast.

50	Plan Development 6.1.1	In integrating its supply and demand side resource, the Company shall prepare an evaluation that takes into consideration the life expectancy of the resource, if the resource provides capacity and/or energy, any improvements to system reliability, the dispatchability of the resource, any lead time requirements, the flexibility of the resource, the Generation Attributes of the resource, the efficiency of the resource and the opportunities for customer participation. The Company shall assess the probability of securing the options according to modeling information used, including any key assumptions. The Company shall provide the estimated energy and capacity impacts for each option and the rationale behind the estimate.	Section 3 and 5.	These factors are considered in the AuroraXMP® model DSM analysis.
51	Plan Development 6.1.2	The Company shall prepare a contingency plan that shall include a discussion of how the Company might alter the proposed IRP in the future if the key planning assumptions used to develop the proposed IRP in the future turn out to be different than what was assumed in preparing the proposed IRP.	Executive Summary	The IRP provides a sensitivity analysis to show the impact of changes in natural gas prices.
52	Plan Development 6.1.3	The Company shall evaluate the cost-effectiveness of the options from the perspectives of the utility and the different classes of ratepayers based on real prices (may also provide an evaluation based upon nominal prices).	Executive Summary	The impact of changing natural gas prices on electric rates for residential and commercial class is shown in the Executive Summary.
53	Plan Development 6.1.4	The Company shall include a current evaluation, detailing and giving consideration to environmental benefits and externalities associated with the utilization of specific methods of energy production (may rely on commonly available published research and not on original research by DPL). To the extent any reliable, relevant peer reviewed published research and scientific and/or medical studies commonly available includes life cycle analyses encompassing energy extraction, transport, generation, and/or use, the Company shall include such research and studies in its evaluation.	Section 8.	The IRP includes an evaluation of the environmental benefits associated with the Reference Case based on analysis provided as part of the 2012 IRP.
54	Plan Development 6.1.4	To the extent that any reliable, relevant peer reviewed published research includes life cycle analyses encompassing energy extraction, transport, generation, and/or use is commonly available, the Company shall include such research and studies in its evaluation.		The 2014 IRP incorporates, by reference, the life-cycle impact analysis completed and filed as part of the 2010 IRP.
55	Plan Development 6.1.5	The IRP shall not include any assumptions that externalities are adequately addressed by either the fact that the IRP meets the RPS, satisfies the EERS, or that the generating units to be utilized comply with existing environmental regulations. This rule does not, however, preclude a potential conclusion that the RPS or EERS in effect at the time adequately address externalities.	Section 8	The IRP includes an evaluation of the environmental benefits associated with the Reference Case based on studies completed in prior IRPs.
56	Plan Development 6.1.6	The Company shall evaluate the financial, competitive, reliability and operational risks associated with the options recommended by the IRP and how these risks may be mitigated over the 10 year planning period. This plan shall include a discussion of the likelihood of the occurrence of such risks.	Executive Summary and Section 9	The IRP provides information on expected energy prices, customer rates, and RPS compliance costs over the planning period.
57	Plan Development 6.1.7	For the options included in the proposed plan identified in the IRP, the IRP shall include an analysis of the fuel risk associated with the proposed Resource Portfolio and how such fuel risk will be mitigated when the proposed IRP is implemented.	Executive Summary	The IRP contains a sensitivity analysis of low natural gas prices compared to the Reference Case.
58	Plan Development 6.1.8	The Company shall perform sensitivity analyses on each of the candidate plans to include variations in key assumptions and to assess the likelihood of planned outcomes. These shall include the impact of proposed or existing rules and regulations on a local, regional, or national level related to climate change.	Executive Summary and Section 9	The IRP contains a sensitivity analyses of the Reference Case related to changes in the price of natural gas. The sensitivity includes an evaluation of the changes in power plant emissions including CO2.
59	Plan Development 6.2	The Company shall forward a copy of the IRP to DNREC and seek input into externalities, including but not limited to, health effects.		DNREC provided input into the use of externalities in their written comments in response to the 2012 IRP. Delmarva used DNREC's comments in preparing the externality analysis provided in the 2014 IRP. DP&L submitted a copy of the 2014 IRP to DNREC on Monday, December 1, 2014.
60	Plan Development 6.3	In developing candidate plans, special attention shall be given to ensuring consistency between the IRP and typical rate-making processes. In addition to the ultimate consumer price associated with the plan, the stability of rates and other factors discussed in Section 5.2 need to be considered in any candidate plan selection.	Executive Summary	The IRP provides an evaluation of the potential change in energy costs and customer rates in accordance with the factors set forth in Section 5.2.
61				
62	Proposed Plan Selection 7.1	The Company shall select and file the proposed IRP that is the most consistent with the criteria set forth in 26 Del. C. Sections 1007 and 1020 and this Regulation. The Company shall provide a description of the options recommended for inclusion in the proposed IRP, including a description of the mechanism or process used for valuing each option. The Company shall describe the rationale behind its selection, including any modeling or methodology used as the basis for selection of the proposed IRP.	Executive Summary, Sections 3, 7, and 9.	These requirements are described in various sections of the IRP and the Appendices.

63	Proposed Plan Selection 7.2	The Company shall provide at a minimum a 5 year forecast of supply rates by customer class that would be anticipated based on the IRP planning assumptions and recommended procurement strategy.	Executive Summary and Appendix 5	The forecast of supply rates is provided in Appendix 5. Forecast supply rates for 2015 - 2018 are considered confidential until the completion of the 2015 SOS Auction process.
64				
65	Implementation Plan 8.1	The Company shall file a 5 year action plan outlining the resource decisions intended to implement the IRP.	Executive Summary	Implementation Plans for each planning objective are provided in the Executive Summary.
66	Implementation Plan 8.1.1	This Implementation Plan shall include all actions to be taken in the first 2 years and outline actions anticipated in the last 3 years.	Executive Summary	Implementation Plans for each planning objective are provided in the Executive Summary.
67	Implementation Plan 8.1.2	For IRPs filed on or after December 1, 2010, the Implementation Plan shall include a status report of the specific actions contained in the previous Implementation Plan, including what risk assumptions were made and what actually occurred.	Executive Summary	The Implementation plans for each planning objective include descriptions of relevant milestones that have occurred since the 2012 IRP.
68	Implementation Plan 8.1.3	The Implementation Plan shall include a schedule of key activities related to the IRP implementation	Executive Summary	The Action plans provide the key milestones expected in the next two years.
69				
70	Review and Comment 9.1	Commencing in 2009 and continuing on an annual bases, the Company shall submit a report to the Commission, the Governor, and the General Assembly detailing their progress in implementing their IRPs.		The Company provided a report on the status of the IRP to the Commission, Governor and General Assembly in December, 2013 and will provide a new report on or before December 31, 2014.
71	Review and Comment 9.2	The Commission , interested State Agencies, interested parties and the general public shall be provided an opportunity for review and comment on the Company's IRP filings. The Commission shall seek input from DNREC on the issues of externalities and environmental benefits due to emissions as a result of the IRP.		It is expected that a schedule for public comment on the IRP will be issued after the IRP is filed on December 1, 2014.
72	Review and Comment 9.3	To the extent that the Commission determines that the IRP is not compliant with the statute or is unlikely to meet the goals of the statute, the Company shall revise its IRP to meet these requirements.		As shown in this Appendix, the IRP is compliant with the provisions of 26 Del. C. Sections 1007, 1020 and accompanying regulations.
73	Review and Comment 9.3	Rate treatment in connection with the treatment of future resource acquisitions shall be addressed in rate or other proceedings as filed by the utility or as initiated by the Commission.		The Company will address rate treatment in rate case or other proceedings as appropriate. The IRP does not request any Commission action on rate treatment.
74	Review and Comment 9.4	DPL must maintain sufficient records to permit a review and confirmation of material contained in all required reports as they are subject to annual review and audit by the Commission and Interested State Agencies.		All records related to the IRP will be stored and available for inspection and audit as needed.
74				

Appendix 2

Delmarva Power
2014 Integrated Resource Plan
Appendix 2
Responsible Parties – 2014 Integrated Resource Plan (IRP)

Name	IRP Area of Expertise
Jack Barrar	IRP Process
Jaclyn Cantler	Transmission
Kemm Farney	Load Forecast
Pamela Scott	Regulatory and Legal Counsel
Susan DeVito	Customer Rates
Lisa Pfeifer	Environmental
Patrick Augustine[i]	IRP Planning Model
Wayne Hudders	Demand Side Management
William R. Swink	Portfolio Design & Renewables Supply

[i] Pace Global

Appendix 3

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF INTERGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DELMARVA POWER & LIGHT COMPANY UNDER 26 *DEL.* C. § 1007 (c) & (d) OPENED DECMEBER 18, 2012	))))))	PSC DOCKET NO. 12-544

ORDER NO. 8574

AND NOW, this 8th day of July, 2014, the Delaware Public Service Commission ("Commission") determines and orders the following:

WHEREAS, 26 *Del. C.* § 1007 (c) (1) requires Delmarva Power & Light Company ("Delmarva" or the "Company") to conduct integrated resource planning; and

WHEREAS, pursuant to 26 *Del. C.* § 1007 (c) (1), Delmarva's Integrated Resource Plan ("IRP") is required to systematically evaluate all available supply options (including procurement, generation, transmission, conservation and load management) over a ten-year planning period, and forecast the appropriate mix of such resources that will be utilized to meet the needs of its Standard Offer Service ("SOS") customers, at minimal cost and without sacrificing adequate reliability; and

WHEREAS, on December 6, 2012, Delmarva filed its IRP pursuant to its statutory obligation; and

WHEREAS, on December 18, 2012, in Order No. 8259, the Commission opened this docket to perform its oversight and review of the IRP, and appointed a Hearing Examiner to make findings and recommendations on Delmarva's proposed IRP; and

WHEREAS, the Commission Staff ("Staff"), the Division of the Public Advocate (the "DPA"), the Delaware Department of Natural Resources and Environmental Control ("DNREC"), the Mid-Atlantic Renewable Energy Coalition ("MAREC"), Sierra Club of Delaware, Calpine and the Caesar Rodney Institute (collectively, the "Parties") intervened or otherwise participated in the proceedings; and

WHEREAS, on March 4, 2013, pursuant to the Parties' request that they be permitted to conduct working group meetings to discuss the IRP, the Hearing Examiner suspended the filing dates for comments required in Order No. 8259; and

WHEREAS, on April 10, May 1, May 14, June 3 and July 31, 2013, the Parties conducted five (5) technical working group meetings regarding the issues raised by various parties, which meetings were publically noticed on the Commission's agenda; and

WHEREAS, pursuant to the schedule established in this Docket, on September 16, 2013, the Parties filed their respective comments on the IRP, and Delmarva filed its responses to those comments on October 16, 2013; and

WHEREAS, subsequently, the Hearing Examiner asked Delmarva to summarize the results of the various working group meetings, which was provided to the Hearing Examiner on April 29, 2014, and along with the Parties' filed comments, was summarized by the Hearing Examiner in his June 2, 2014 Findings of Fact, Conclusions of Law and Recommendations; and

WHEREAS, since no settlement was proposed by the Parties, and the Hearing Examiner assumed that the Parties would make oral presentations to the Commission, he made no specific recommendations concerning the IRP, concluding only that there was ample evidence that the requirements for public investigation and comment had been satisfied under 26. *Del. Admin. C.* § 3010.9.2; and

WHEREAS, the Commission met in public session on June 26, 2014, to hear the Parties' comments and conduct deliberations on the issues summarized in the Hearing Examiner's Report; and

WHEREAS, Delmarva stated that it had reviewed the comments received from the Staff, DPA, DNREC, CRI, MAREC and Delaware's Sustainable Energy Utility ("SEU") and indicated that it would address those comments, including but not limited to the concern expressed by MAREC and other parties regarding the inclusion of a 15% energy savings goal in the next IRP, which all Parties agreed was not achievable in the immediate future;

NOW, THEREFORE, IT IS ORDERED BY THE AFFIRMATIVE VOTE OF NOT FEWER THAN THREE COMMISSIONERS:

1. The Commission ratifies the IRP appended as Exhibit "A" to the Hearing Examiner's Report, as filed in compliance with the Electric Utility Retail Customer Supply Act of 2006 ("ERUCSA"), 26 *Del. C.* § 1001 *et seq.* and 26 *Del. Admin. C. §3010.*

2. The Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

/s/ Dallas Winslow
Chair

/s/ Joann T. Conaway
Commissioner

/s/ Jaymes B. Lester
Commissioner

/s/ Jeffrey J. Clark
Commissioner

Commissioner

ATTEST:

/s/ Alisa Carrow Bentley
Secretary

Appendix 4

Pepco Holdings Inc

Appendix 4

2014 Load Forecast Documentation

Peak Demand Forecasting

Electric Sales Forecasting

Electric Customer Forecasting

Regional Economics

delmarva power

PHI Economics and Forecasting Group

Table of Contents

I. Introduction

Business Purpose of This Document

This document explains the process used by Delmarva Power and Light Company (DPL) in preparing the projections of electric energy and power demand submitted as part of the Company's Integrated Resource Plan in Delaware. The purpose is to make those projections transparent, so that any interested reviewer will be able to clearly understand the procedures that were used. Throughout these discussions of forecasting, the goal is to build a consensus that the results are "not unreasonable."

The remainder of this chapter provides a discussion of business forecasting, focused on how business forecasting practices may differ from textbook treatments of statistics and econometrics. The chapter then continues with an overview of how the models used in preparing these projections are constructed, and concludes with a discussion of forecast accuracy.

Chapter II discusses the data considerations that influence or limit the range of forecasting techniques available. It also discusses the most important assumptions that are used in the projections.

Chapter III discusses PHI's coverage of regional economic conditions in the state of Delaware and the Metropolitan Statistical Areas representative of the DPL footprint.

PHI Economics and Forecasting Group

Chapter IV describes the role of prices in PHI's forecasting practice and the evidence for price sensitive sales and power demand.

Chapter V discusses PHI's weather normalization procedures and incorporation of weather into the forecast.

Chapter VI reports the projections of energy requirements by class of customers.

Chapter VII reports the projections of customer formation by class.

Chapter VIII presents the DPL Baseline forecasts for the Delmarva Zone in the PJM transmission area. This forecast has been prepared by PHI independent of the forecast published by PJM in their PJM Annual Load Report.

Chapter IX reports alternate scenario projections of power demand and energy requirements. Alternate scenarios include weather, high growth, and low growth scenarios.

A glossary provides data definitions for included energy and demand variables, weather related, economic, and dummy variables.

Brief Overview of Business Forecasting

Forecasting is an economic activity. A "better," more involved, more complicated, more expensive forecast is only worthwhile if it creates even more value for the organization. In many cases smaller and simpler forecasts work perfectly well for the need at hand.

While statistical analysis is highly mathematical, the discipline of forecasting is most definitely an art. In forecasting we routinely acquire and utilize data as a commodity. Data is not a commodity; instead, every data item requires careful and critical scrutiny. Strictly speaking, there is no such thing as data. Instead, the normal conduct of our business activities generates a flow of documentation—meters are read, bills are printed mailed, payments are received—and that documentation is then more or less carefully collated and used by us as data. The creation of data is strictly the byproduct of unrelated commercial activity.

Take for example the economic concept of "employment." It seems unambiguous at first; we're obviously talking about the number of people that have jobs. But it's not that simple. All we know about employment begins with the ES-202 data. ES-202 employment data is the collation of Employment Security Form No. 202, the form that all employers must fill out each month so that their employees will be covered by unemployment insurance.

Not all workers are covered by Unemployment Insurance. For example, contractors, farm workers, and several other categories of employees do not qualify. They are not counted in the ES-202 data. To make up for this, the US Bureau of Labor Statistics prepares estimates inclusive of these categories. This augmented data, called the BLS-790 data, has a much longer reporting lag of about 18 months, but does include estimates of these other workers.

Finally, the US Department of Commerce Bureau of Economic Analysis prepares the BEA Personal Income, Population and Employment estimates that incorporate all of the prior information, and also include survey data from the County Business Patterns surveys. The BEA employment data are annual, and are available on an even longer reporting lag of approximately two years.

All of these estimates of employment are treated as data. They are all different, and sometimes they are very different. The right choice of employment estimate depends entirely on the situation faced by the forecaster. And none of them tell you the "real" level of employment.

At the most basic level, business forecasts must serve the planning needs of the business in an independent, informed and objective manner. At the same time, forecasting is an economic activity. A more involved, more complicated, more expensive forecast is only worthwhile if it creates more value for the business. In many cases smaller, simpler, more straightforward forecasts provide reasonable results. Our modeling approach does not include an end-use approach for precisely that reason, the costs are not justified. Of course, the most important component in any forecast is the good judgment and expertise of the team of forecasters.

PHI Economics and Forecasting Group

The approach used at DPL includes the concept of "mutually confirming forecasts." Wherever possible, independently prepared forecasts are used to provide support of the forecast. For example, in preparing the outlook for the Delmarva Zone, independent forecasts of retail sales, the amount of energy throughput for the zone and the peak demand for the zone are prepared. It is expected that forecasts of the load and throughput will provide a consistent view of the future. The reasonableness of the independent components of the forecast raises DPL's confidence in the forecast.

Forecast Accuracy

Utilities' internal view of forecast accuracy is almost always decided by the credibility of the individual forecasters before their management committee. Rigorous discussions of forecast technique that get down to a critical examination of a forecaster's methods are unusual.

As a result, the quality of these forecasts varies all over the board. As hard as it may be to believe, a few utilities are still very proud of the fact that a ruler and logarithmic graph paper provide results suitable to their needs. At the other extreme, there are companies spending several person-years of internal staff time and hundreds of thousands of dollars on consultants during each budget cycle. In reviewing utility forecasts it is always important to bear in mind that forecasting is itself an economic activity – it is only worthwhile spending more on a forecast if the benefits outweigh the costs – as assessed by senior management.

DPL's interpretation of forecast accuracy is that there are two considerations. First, forecasts should be unbiased; in the sense that errors should be expected to be zero at the time the forecast is made. Second, forecasts should be risk minimizing, in the sense that the confidence bands around the forecast should be as small as possible.

Forecast risk should be measured as the standard error of the forecast, although that concept is difficult to calculate. In fact, it cannot be calculated directly, although it can be shown that the standard error of the forecast is a function of the standard error of the regression, the number of variables in the regression equation and the distance from the historic mean of the variable being explained.

As shown in Appendix F, the standard error of the regression for the regression relationship used to forecast the peak hour demand in the Delmarva Zone is 172 mW, with a historic average peak demand of 2,832 mW (average of monthly peak demand, 1993:5-2013:10). If the relationship was used to predict the peak hour demand at the mean of the historic data, 95% confidence bands surrounding the forecast would be +/-172*2 or +/-344 mW wide. In other words, the width of the confidence interval is roughly 12% of the underlying series, calculated at the mean of the historical value (which also happens to be its minimum value).

The relationship between the number of explanatory variables and the standard error of the forecast leads to a Principle of Parsimony, that argues that each variable included in the equation must pay its way by way of explanation, because it presents another source of risk to the forecast. The fact that the standard error of the forecast increases as one moves away from the mean of the historical data gives rise to the observation that confidence bands are "trumpet shaped," i.e., the standard error of the forecast gets bigger as the forecast tries to look farther out into the future.

The data in Table I.1are drawn from PJM's annual Load Reports. Table I.1 illustrates the errors (the difference between expected loads and actual observed loads) for 1-year forecasts, 2-year forecasts, and so on out to 8-year forecasts. Beyond eight years there are not enough data points to estimate a standard error.

PHI Economics and Forecasting Group

Table I.1

Zonal Peak Demand Forecast Accuracy

DPL Zone	1-Year	2-Year	3-Year	4-Year	5-Year	6-Year	7-Year	8-Year
2013 PJM Unrestricted Forecast	11							
2012 PJM Unrestricted Forecast	1	36						
2011 PJM Unrestricted Forecast	78	63	96					
2010 PJM Unrestricted Forecast	(27)	19	43	89				
2009 PJM Unrestricted Forecast	12	(48)	68	179	265			
2008 PJM Unrestricted Forecast	182	318	310	372	412	487		
2007 PJM Unrestricted Forecast	(54)	156	296	294	362	380	447	
2006 PJM Unrestricted Forecast	(106)	(90)	140	284	263	333	381	457
2005 PJM Unrestricted Forecast	(42)	43	127	362	527	551	646	721
2004 PJM Unrestricted Forecast	105	(46)	37	122	362	535	570	678
2003 PJM Unrestricted Forecast	50	189	72	148	224	460	626	651
2002 PJM Unrestricted Forecast	(35)	81	179	16	66	122	343	461
2001 PJM Unrestricted Forecast	(77)	(100)	15	111	(54)	(6)	49	268
2000 PJM Unrestricted Forecast	19	(112)	(174)	(102)	(46)	(244)	(209)	(168)
1999 PJM Unrestricted Forecast	117	(23)	(132)	(183)	(100)	(35)	(232)	(202)
1998 PJM Unrestricted Forecast	82	115	(23)	(131)	(181)	(96)	(30)	(225)
1997 PJM Unrestricted Forecast	(79)	(176)	(246)	(335)	(455)	(716)	(792)	(770)
1996 PJM Unrestricted Forecast	(6)	(97)	(267)	(283)	(377)	(641)	(704)	(749)
1995 PJM Unrestricted Forecast	(79)	(92)	(174)	(275)	(261)	(352)	(468)	(522)
1994 PJM Unrestricted Forecast	(9)	(80)	(270)	(352)	(415)	(401)	(491)	(607)
1993 PJM Unrestricted Forecast	112	10	97	(48)	(123)	(221)	(208)	(298)
1992 PJM Unrestricted Forecast	(67)	(68)	(180)	(110)	(310)	(405)	(520)	(523)
Mean Error ('92-'13)	8.55	4.67	0.70	8.32	8.83	-14.65	-37.00	-55.20
Standard Error ('92-'13)	77.34	119.07	177.55	234.74	311.60	418.05	488.01	542.98

Based upon our experience, DPL believes that these data are representative of the results that would be reported for other similar forecasts. It has been DPL's experience that utility forecasts are usually unbiased. It has also been DPL's experience that the risk associated with demand forecasts is much higher than most readers of forecasts expect – the future can only be known with great uncertainty. Finally, it has been DPL's observation that the risk associated with the forecast, or the standard error of the forecast, grows slowly at first as the time horizon of the forecast is extended, but eventually begins to expand at an increasing rate and quickly become very large.

PHI Economics and Forecasting Group

Modeling/Forecasting Philosophy

One of the most vitally important planning tools for energy retailers is the econometric model and forecasting system. Its advanced precision assists the retailer in the generation of forecasts that will withstand the scrutiny of regulators and senior executives alike, as well as maintain its credibility over time. In addition, such tools can be helpful in attaining the most important result, which is the prevention of imbalances between energy demand and availability.

The PHI Economics and Forecasting Group has designed, built, tested, and estimated an Electricity and Electricity Peak Load Forecast System (the "PHI Forecast System"). The system incorporates the features of the PHI Economics and Forecasting Group's basic modeling philosophy. This philosophy recognizes that the ideal econometric features of a model whose purpose is forecasting can often be quite different from the ideal features of a model intended for research purposes.

The most important difference is that a model intended for research purposes is tailored to yield good hypothesis tests on the parameters. This means that the builder of such a model is likely to have searched for explanatory variables that yield high t-statistics, a high priority in variable selection for models of this type.

In contrast, the PHI Economics and Forecasting Group believes that identifying regressors that perform well in t-tests of parameter significance is only one of several objectives that a modeler should try to attain, instead of the most important one. PHI takes the view that an over-emphasis upon high t-statistics does not necessarily lead to the attainment of the very most important criterion that a forecasting model must meet—a low forecast standard error.

In addition, the emphasis upon high t-statistics could lead the researcher to include in the model equations having lagged dependent variables among the explanatory variables. Such an inclusion could cause its own distinct set of problems. Models consisting of equations that make use of lagged dependent variables tend not to yield good forecast results. The most important problem is that such models are not really causal models, and thus are generally ineffective at predicting turning points. The models are likely to overstate energy consumption during economic downturns and understate it during economic expansions. In addition, the use of lagged dependent variables in equations is liable to render the model inappropriate for policy or impact analysis because of the resulting biased elasticities.

Intellectually, the use of lagged dependent variables amounts to placing a ruler on the most recent realized observations and making the case that the future will be pretty much like the past exclusively because the lagged dependent variable parameter often scores well in tests of parameter significance. For these reasons, an important part of the DPL Economics and Forecasting Group's modeling philosophy is the sparing use of lagged dependent variables.

PHI Economics and Forecasting Group

As indicated above, the PHI Economics and Forecasting Group puts a high priority upon attaining a minimum standard error of regression, when selecting equations in the process of model building. This is generally accomplished through three main methods:

- Diagnostic use of summary statistics,
- Correct modeling of seasonal patterns,
- Including a correction for serial correlation.

The PHI Economics and Forecasting Group does not use summary statistics as decision rules for selecting an equation, but instead as diagnostic tools in searching for the smallest possible standard error of regression. Reducing the standard error of the regression generally reduces the standard error of the forecast, and improves the ability of the model to provide "reasonable" forecasts.

Forecasters too frequently either ignore or treat incorrectly the problem of serially correlated residuals. Correcting for serial correlation through the use of something as simple as appropriate differencing or through the use of a Cochrane-Orcutt or Hildreth-Lu procedure often serves to reduce the standard error of the regression — and hence the standard error of the forecast — dramatically, providing more efficient forecasts.

Of course, the PHI Economics and Forecasting Group employed other criteria as well in judging candidate equations in the construction of the PHI

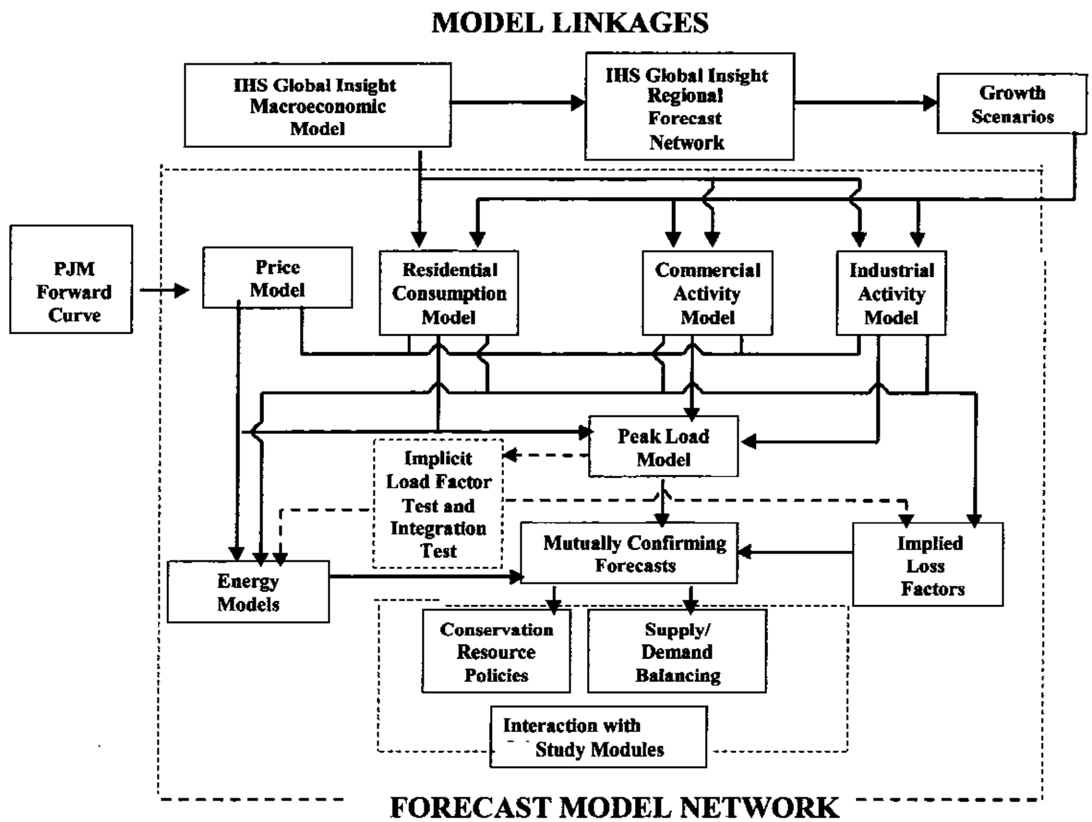
Forecast System. Of central interest was the theoretical and empirical specification of the model as a whole. Estimated coefficients were required to pass rigorous tests of reasonability drawn from the PHI Economics and Forecasting Group's past experience with other models.

PHI's modeling approach for energy demand employs a regional economic activity sub-model to economic growth scenarios for the DPL service areas that drive the customer demographics, sectoral energy consumption and peak load sub-models. Figure I.1, below, illustrates, for the case of electricity demand and peak load components of the model, how the sub-models are related to one another. It also shows how these sub-models are related to their external driver models, such as the IHS-Global Insight Macroeconomic (national) Model and the IHS-Global Insight Regional Forecast Network (which models the individual states and Metropolitan Statistical Areas included in the DPL service areas).

PHI Economics and Forecasting Group

Figure I.1

The PHI Load Forecast Model Network



The key economic variables that are drawn from the Global Insight outlook include local employment, local incomes and the rate of inflation. Other exogenous factors include the commodity component of the price of electricity, which is taken as the PJM Forward Curve as posted by the New York Mercantile Exchange (NYMEX). The total all-in retail end-use price of electricity, inclusive of taxes, surcharges and the commodity cost of electricity is calculated using a deterministic spreadsheet model that replicates the Company's supply portfolio. We expect estimated price elasticities to fall within a reasonable range consistent with our expectations given economic theory and industry consensus.

II. Assumptions and Data Considerations

PHI prepares its forecasts for DPL DE and the Delmarva zone utilizing an integrated econometric sales and load modeling network. The forecasting approach relies heavily on the preparation of forecasts for key concepts that are prepared independently, with the expectation that mutually confirming results should raise the confidence that can be placed in the forecast.

The forecasting model uses monthly data that in most cases goes back to 1991. 1991 was chosen because there have been two complete business cycles since 1991, and it seems like there has been structural change in our local economies since the 1980s.

The weather data that is used in preparing the forecast for DPL DE is collected and reported by NOAA, reflecting conditions at the New Castle County Regional Airport. PHI maintains hourly weather data back to 1964, and constructs all of the weather metrics that are used in forecasting from this raw data. For most forecasting exercises the expected values for each of the weather metrics are their normal, or average, values taken over a rolling 20-year period. For the extreme weather scenario, the normal weather values are defined as their 20-year normal values plus two standard deviations.

Projections of economic and demographic activity in the local economy are purchased from Global Insight. GI updates its forecast products monthly, usually during the third week of the month. A narrative discussion of the Mid Atlantic economies prepared by IHS-Global Insight is included as Appendix B.

Projections of the price of electricity are based upon a deterministic spreadsheet model of the Company's supply portfolio. It is believed that households make rational electricity consumption decisions based upon the all-in real cost of electricity, inclusive of all taxes, surcharges, and the commodity component of the electricity price. Since we do not have data on the commodity cost of electricity for choice customers, we assume their commodity costs are the same as for the Standard Offer Service (SOS) customers. It is assumed that costs, taxes and surcharges associated with the wires business will increase with general inflation. It is assumed that the price of the commodity component will escalate with the PJM forward curve, as posted on the NYMEX.

III. Regional Economic Activity

All three components of the PHI Forecast System; electricity sales, customers and electric peak load, incorporate the assumption that demand will depend upon economic conditions in the service territory. More specifically, each demand forecast in the system explicitly incorporates local employment for the Metropolitan Statistical Areas (MSA) representative of the DPL service territory. The mapping of economic statistics to the service territory is illustrated in Appendix A (maps were prepared by the U.S. Department of Commerce Census Bureau). The Company's analysis has shown that the DPL DE service territory is best represented by local economic activity in the Wilmington and Dover MSA. While DPL DE does not serve the City of Dover, the Company does serve much of the Dover MSA that is outside the City. In addition, activity within the City of Dover spells over into the area served by the Company outside the City.

Historical and forecast employment and income data for the MSAs are acquired from the company's economic consultant Global Insight, and explicitly incorporated into PHI's econometric forecasting models. While employment and income are the richest and most important regional economic concepts to model explicitly, the PHI forecasting team collects economic information on a wide range of concepts to form a comprehensive view of economic conditions in the service territory.

PHI Economics and Forecasting Group

Last, the group makes every effort to analyze the data we receive and produce independent analysis of the economic landscape. As we receive our economic forecast from an external consultant, we spend a significant amount of time understanding the assumptions underpinning the GI forecast. Provided in Appendix B are write-ups associated with the latest GI forecast, highlighting key assumptions for their outlook of the Wilmington MSA, Dover MSA, and the state of Delaware. These reports are reviewed monthly after the release of each new GI MSA, state, or macroeconomic forecast.

IV. Prices

It's expected that consumers will respond to changes in the price of a commodity by changing their consumption of that commodity. While many different measures of prices are possible, the Company finds that the most useful measure of price in forecasting electricity sales and demand is average revenue per kWh for the rate or revenue class. In the statistical relationships that are estimated it is assumed that customers respond to the total all-in real price of electricity. The price is real in the sense that it is adjusted for changes in purchasing power as measured by the US consumer price index. The price is all-in when it reflects all of the costs the consumer faces when purchasing electricity, including the commodity cost of electricity, all utility taxes and surcharges, and all base transmission and distribution charges.

Table IV.1, below, shows the sensitivity of electricity consumption to the real all-in price of electricity for DPL DE customers by revenue class. The real all-in price of electricity is calculated as the sum of all commodity costs, utility taxes and surcharges and base distribution and transmission revenues expressed on a cost per kWh basis and adjusted for the effects of inflation using the US Consumer Price Index.

PHI Economics and Forecasting Group

Table IV.1

PHI Sales Forecast Model
Estimated Price Elasticitities, August 2010

	DPL DE
Total Residential	
Residential Non Heat	-0.1051
Residential Heat	-0.1294
Commercial	-0.0378
Industrial	-0.1403
Street Light	-0.1137

The price elasticity of electricity measures consumers' response to changing prices as the percentage change in the quantity of electricity consumed when the real price of electricity changes by 1%. For example, if the price elasticity for the residential non space heat customer class is estimated to be -0.1, as in Table IV.1, a 1% increase in the real price of electricity will lead to a -0.1% decrease in the consumption of electricity by that customer class.

For the calculations reported in Table IV.1, the price elasticity is calculated as the percent change in quantity related to a percent change in price as of August 2010. The regression coefficient calculated in August 2010 was taken as the best estimate of the change in the amount consumed given a one unit change in price. The regression coefficient was multiplied by the real price prevailing in August 2010 and divided by the amount sold during August 2010 to yield the elasticity.

Figure IV.1 illustrates the real and nominal price history for DPL DE residential customers. The black line represents the nominal price, showing the period of the stipulation against rate increases and the rate increases that occurred when the stipulations came off. The red line represents the real price in 2012 dollars, and clearly shows that the period of falling real prices during the period of the stipulation is almost exactly offset by the price increases that occurred over the last decade, leaving the real price of electricity over the 20 year period almost unchanged.

Figure IV.I

Real and Nominal All-In Price of Electricity

($/kWh, current and 2012$)

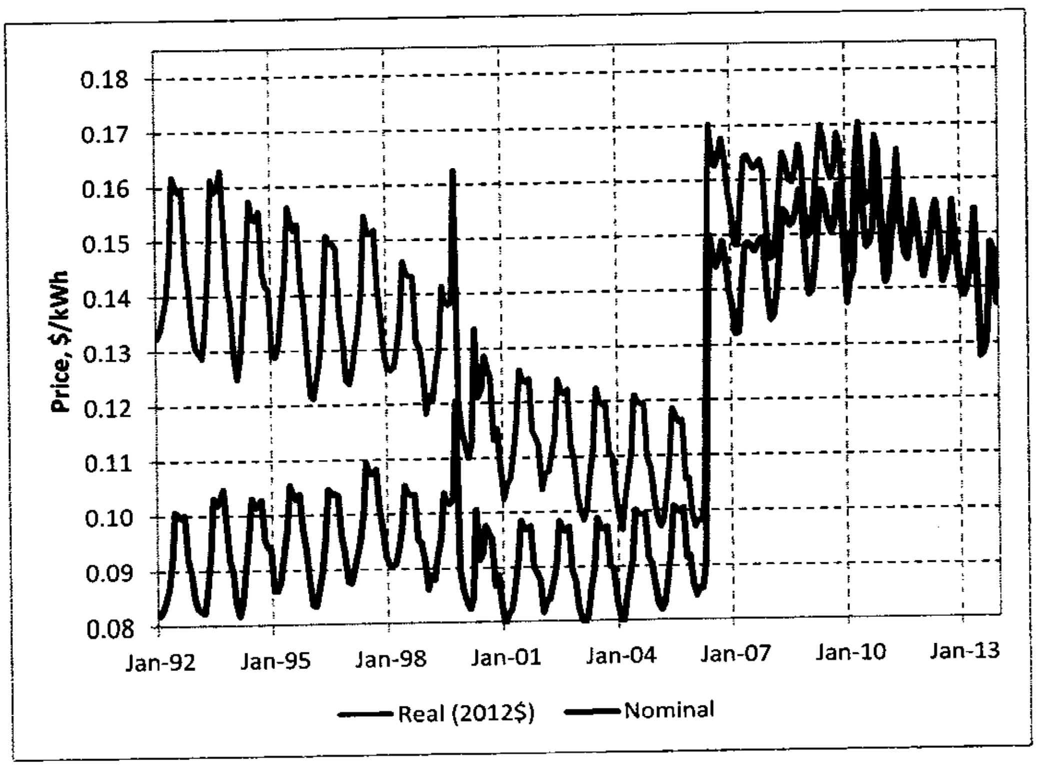


Figure IV.2 illustrates the forecast of real, all in electricity prices used in the DPL DE forecasts. To prepare price projections, the components of the all in price are divided into the commodity portion and the non-commodity portion, consisting of utility taxes, surcharges and base transmission and distribution charges. Nominal prices are converted to real using the US Consumer Price Index, All-Urban, with prices expressed in 2012 dollars.

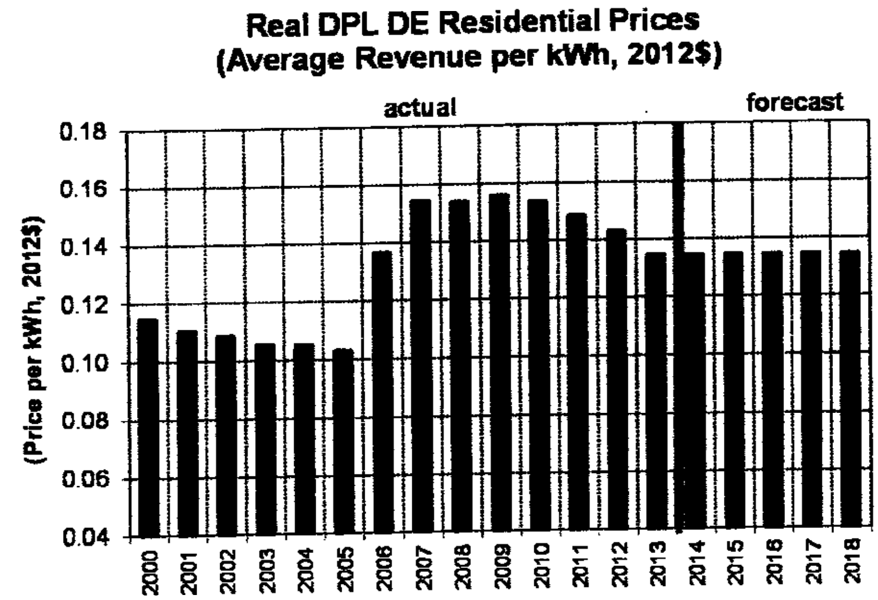
In Figure IV.2 the non-commodity portion of prices is assumed to grow with the rate of general inflation. The commodity component of prices is projected by modeling the supply portfolio.

In DPL DE the supply portfolio is divided into three tranches, and the contracts for the supply of one tranche are renewed each year, with all of the contracts renewed after a cycle of three years. Once each year, in November, the prices paid by consumers are updated to reflect changes in the supply portfolio made during the previous June.

In preparing the projected supply portfolio costs, it is assumed that as each tranche of contracts is renewed, the contract price will be the current forward price for the month when the contracts will be renewed, as measured by the NYMEX forward curve for electricity trading at PJM-West.

Figure IV.2

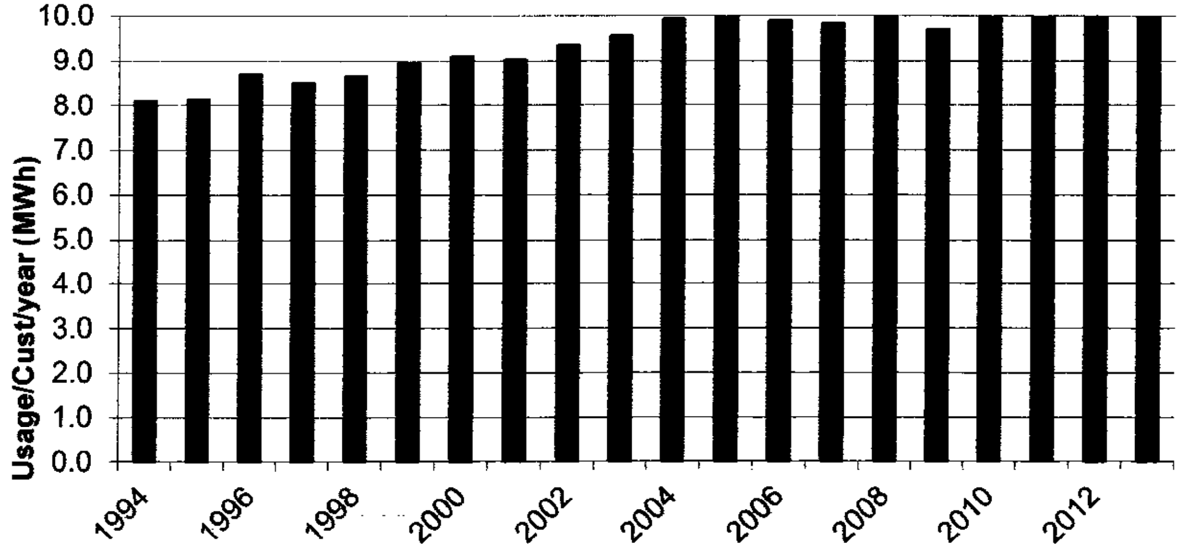
Real Price of Electricity, History and Forecast



By way of comparing historical prices with usage per customer, Figure IV.3 illustrates historical usage per customer. Figure IV.3 shows clearly the period of increasing usage per customer following the beginning of the period of price stipulations and the end of increasing usage when the stipulations ended and the first rate increases were allowed. During the forecast period it is expected that the real all-in price of electricity will be nearly constant – flat real prices – and as a result it is expected that usage per customer will remain stable over the forecast time horizon.

Figure IV.3

Usage per Customer (Response to Price)



V. Weather Normalization

The Effects of Weather on the Forecast

Currently, the weather data parameter used in the sales forecasting process is Cooling and Heating Degree Days on a 65° basis. In the peak forecasting process it is Cooling Degrees on a 65° basis and Heating Degrees on a 65° basis. The weather data used in the forecast needs to meet two criteria, it should theoretically relate to geographic sales territory and it should not be biased.

In the forecast, the relationship between historical weather and the historical sales or peaks is modeled using regression analysis. Then normal monthly weather is calculated and assumed to be the weather in the future. The effect of weather data in the forecast period should be neutral. When normal weather is used, in the unlikely event that the actual weather in a given month happens to be normal, then the weather effect on sales/peaks is zero. Unlike every other independent variable in the model, we do not forecast weather. Once actual sales and actual weather is known for a given month, the variance in actual from budgeted sales caused by the variance in actual from normal weather is determined by, again, performing regression analysis.

The weather data used in the later regression analysis should be that weather data that corresponds closest to the appropriate geographic region and represents the weather that affects the behavior of consumers. Since the variance from actual to normal weather is used to determine the effect on actual sales, it is only logical to use the same data in the former regression analysis.

In the forecasting process weather normalization is not used *per se*. The current forecast models use approximately 20 years of actual data. This data is not weather normalized; it is the actual historical sales. The forecast period assumes weather will have no effect on sales. It assumes normal weather.

Weather normalization is a process that adjusts actual sales/peaks to what they would have been if the actual degree days had been at their historical normal level. This is based on the past relationship between actual degree days and actual sales/peaks.

Weather normalization is an inexact process, degree days are a one variable proxy for a complicated, multivariate phenomena, the weather, that takes into account only one of those variables, the average daily temperature departure from 65 degrees. The relationship between degree days and sales/peaks is not a linear one. The normalization process adjusts sales for weather using a linear model; this makes weather normalization, at best, an approximation.

The various revenue classes have different sensitivity to changes in degree-days, residential being most affected, non-space heat being least affected.

However that does not mean that there is no relationship between weather and the so called non-weather sensitive classes, during near normal weather there is no change, but there is during extreme weather, again these instances being too rare to accurately model.

Finally, there are always other variables at work that will affect sales/peaks; these other variables are generally unknown or known only anecdotally. In either case these variables are either not measured or not measurable. Therefore, they cannot be modeled.

Mapping of Weather Stations to Loads

Currently DPL uses weather data measured at the New Castle County Regional Airport (Wilmington Airport.) A weather station needs to provide at least thirty years of continuous hourly data to allow for calculation of normal weather and to support special studies. Wilmington Airport meets this standard. Some alternative Delaware weather stations are shown in the table V.1 below.

Table V.1

Alternative DE Weather Stations

Location	Station ID	Temp. Frequency	Status	2005 Avg. Temp.
Wilm. Porter Reservoir	79605	Daily	Open	54.83
Newark University Farm	76410	Daily	Open	54.47
Dover DELDOT Office	72730	Daily	Open	55.68
Greenwood	73595	Daily	Closed	54.41
Milford	75915	Daily	Closed	55.44

Source: David T. Stevenson, Director, Center for Energy Competitiveness, Caesar Rodney Institute, email to Jack E. Barrar dated 4/13/2012.

How Weather is Modeled

DPL collects hourly weather data from NOAA. This is used in different ways in the peak and sales model. In the peak model the weather parameter is recorded *at the time of the peak* for each month of history. The 20 year average of this weather parameter is the normal weather for that month. Since, the weather parameter, at the time of the peak, is going to be close to the maximum weather of that day, we characterize this as the extreme normal. In the peak load model, the current weather parameter is Heating Degrees 65° Base and Cooling Degrees 65° Base. This is defined as the amount of the current (at the time of the peak) dry bulb temperature in degrees Fahrenheit over 65 for Cooling Degrees and under 65 for Heating Degrees.

Table V.2

Example of Cooling/Heating Degrees for a given Hour

Current Temperature	Cooling Degrees (65°)	Heating Degrees (65°)
55°	0°	10°
65°	0°	0°
72°	7°	0°

In the sales models the weather parameter for each hour of each day of each month of history is recorded. The average of the hourly dry bulb temperature for each day is recorded. The monthly sum of the daily averages of the weather parameter is recorded. The 20 year average of this weather parameter is the normal weather for that month. In the sales models, the current weather parameter is Heating Degree Days 65° Base and Cooling Degree Days 65° Base. This is defined as the amount the daily average dry bulb temperature in degrees Fahrenheit is over 65 for Cooling Degree Days and is below 65 for Heating Degree Days. Note the difference between the sales and peak weather parameters. For the peak they are called

Heating/Cooling Degrees, for the sales they are called Heating/Cooling Degree-Days. This is because for the peak, it is a weather parameter for a single hour, for sales it is a weather parameter for a month.

Calendar Month and Billing Month

There is one further step before the sales weather parameter is completed. The Degree Days need to be converted to a Billing Month Basis. This is in recognition of the fact that the sales which are reported in any given calendar month, did not necessary completely occur during that calendar month. This is due to the Billing Cycle and the Meter Reading Schedule. It is beyond the scope of this document to give a complete treatise on these subjects.

A quick example should suffice. A customer has his meter read on the 2nd day of May, because that this customer is on a certain Billing Cycle. However because of the occasional incongruity of the Meter Reading Schedule, the last time this customer's meter was read was on the 30th day of March. The calendar month sales report will show all of this particular customer's usage to have occurred in May. In reality the vast majority of this customer's usage took place in the month of April. Most customers' usage patterns fall into varying degrees of this example.

To compensate for that, weather normalization for sales is not done on a calendar month basis, but on what is called a billing month basis. This is done by compiling the daily weather parameters into half month blocks, these blocks are then weighted to approximate average usage patterns. The following formula is used:

For any given calendar month:

- The sum of the first 15 days of Degree Days of the previous calendar month is multiplied by .25
- The remaining Degree days of the previous month is multiplied by .75
- The first 15 days of Degree Days of this calendar month is multiplied by .75
- The remaining Degree Days of this calendar month is multiplied by .25
- The sum of these four calculations equals this month's Billing Month Degree Days.

Scenarios for 90/10 Weather

The PJM Standard for Weather Sensitivity Analysis is called a 90/10. Using statistical methods, an upper and lower band is set for weather. It is determined what the weather conditions would be so that there is a 90% likelihood that these conditions would not be exceeded. The lower end of the band represents those weather conditions that there is only a 10% possibility that that these conditions would not be exceeded.

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Weather Normalization Factor Estimation

The procedure for preparing the factors used in weather normalization at PHI is to regress daily sales by class against daily heating or cooling degrees, and then to use the estimated coefficients on the weather terms as the weather normalization factors.

Daily sales data by revenue class for the study period are used as the dependent variables in regression studies. Each regression equation includes a constant term, weather variables measuring heating and cooling degree days, and two dummy variables for Saturdays and Sundays. Holidays are included as a separate dummy variable for each holiday. All weather data are received from the US National Oceanic and Atmospheric Administration (NOAA); weather data is measured at the Wilmington Airport.

A set of regressions is estimated for the summer cooling season, in which the weather metric is Cooling Degree Days measured on a comfort threshold of 65 degrees Fahrenheit. A second set of regressions is estimated for the heating season, in which the weather metrics are Heating Degree Days measured on a comfort threshold of 65 degrees Fahrenheit and Heating Degree Days measured on a comfort threshold of 35 degrees Fahrenheit. In both cases lagged weather variables are allowed if the current weather variable is significant. Each seasonal set of regressions includes an equation for each rate or revenue class, depending upon the level of detail available from market settlements. Finally, each equation includes an autoregressive correction.

For example, in the 2014 study that was completed in December 2013, the summer period was defined as April 1, 2013 through September 30, 2013. The winter period was defined as December 1, 2012 through March 31, 2013. Each equation is examined carefully for reasonableness of the estimated coefficients. Where variables do not pass a Student's t-test for significance, the variable is deleted. When an equation contains more than one insignificant term, insignificant terms are deleted in a reverse stepwise fashion. An exception is made with dummy variables for Saturday and Sunday; these two dummy variables are always included, even if they are insignificant.

Once the regression equations are complete, the coefficients associated with the two heating terms with comfort thresholds of 35 degrees and 65 degrees are designated as the weather normalization factors for the heating season, by class. Similarly, the coefficient in each equation for the cooling degrees term is taken as the weather normalization factor for the summer cooling season, by class. Appendix C reports the weather normalized factors estimated for each year for the period 2010-2014.

How Are Sales (kWh) Weather Normalized?

The Company weather normalizes sales by making an additive weather normalization adjustment to actual sales. The weather normalization adjustment is equal to the amount of sales calculated to be above (or below) the sales that would have occurred if the weather had been normal. The weather normalization adjustment is estimated by multiplying the difference between actual weather and normal weather, measured as degree days, multiplied by a weather normalization factor for each revenue class. Multiplying the weather normalization adjustment to sales by class times the average rate per kWh for that class and for that month yields the weather normalization adjustment to revenue.

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VI. DPL DE Energy Forecast

Introduction

The PHI Forecast System produces projections of electricity sales using explanatory variables selected according to economic theory. Electricity demand is derived from the demand for the services of a stock of capital goods that use electricity as a primary energy input. As a result, the stock of space-conditioning appliances is an important explanatory variable.

Once the inventory of appliance stocks is known, the rate at which those stocks are used determines energy consumption. This rate might be influenced by the price of electricity or natural gas, weather conditions, and in the case of industrial customers, the level of manufacturing output.

A substantial share of electricity is sensitive to weather. This dependence is represented in the sales equations by the inclusion of weather variables. This allows the calculation of expected electricity sales over the forecast horizon by inserting hypothetical normal weather and deviations from normal weather into the sales forecasting equations.

Each equation of the DPL DE Power Delivery Electric Forecast System explains electricity consumption in one of several revenue classes of sales:

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- Residential Non-Space Heating Electric Sales (mWh),
- Residential Space Heating Electric Sales (mWh),
- Commercial Electric Sales (mWh),
- Industrial Electric Sales (mWh),

The inputs of the electricity forecasting model are the forecasts of service territory economic activity, the customer models, future weather and future real prices for electricity. The output of each equation is a monthly forecast of electricity sales corresponding to a revenue class and sub-region.

Table VI.1 reports DPL DE electric sales (mWh) by year from 2001 through 2013. Prior to the beginning of the Great Recession, total residential sales usually grew in excess of 2% annually. Since the end of the recession residential sales growth has slowed and become more erratic; growth was only 0.9% in 2011, -1.3% in 2012, and 0.7% in 2013. In 2013, 35% of residential sales are normally made to the residential space heat class. Finally, DPL DE residential electric sales amounted to about 87% of DPL DE commercial sales, although the relationship is not constant.

Table VI.1

DPL DE Historical Electric Sales (mWh)

	Residential Non Space Heat Sales (MWh)	Growth (%)	Residential Space Heat Sales (MWh)	Growth (%)	Commercial Sales (MWh)	Growth (%)	Industrial Sales (MWh)	Growth (%)	Public Street Light Sales (MWh)	Growth (%)	Total Sales (MWh)	Growth (%)
2001	1,647,632		997,223		3,137,968		3,382,502		42,161		9,207,487	
2002	1,771,755	7.5%	1,004,207	0.7%	3,156,168	0.6%	3,361,101	-0.6%	37,712	-10.6%	9,330,943	1.3%
2003	1,771,533	0.0%	1,094,897	9.0%	3,201,446	1.4%	3,747,812	11.5%	36,072	-4.3%	9,851,760	5.6%
2004	1,845,713	4.2%	1,083,339	-1.1%	3,310,333	3.4%	2,624,287	-30.0%	36,032	-0.1%	8,899,704	-9.7%
2005	1,906,492	3.3%	1,087,307	0.4%	3,451,947	4.3%	2,520,242	-4.0%	36,754	2.0%	9,002,741	1.2%
2006	1,892,997	-0.7%	1,074,100	-1.2%	3,512,590	1.8%	2,378,548	-5.6%	37,186	1.2%	8,895,422	-1.2%
2007	1,898,039	0.3%	1,040,148	-3.2%	3,558,184	1.3%	2,357,339	-0.9%	37,549	1.0%	8,891,259	0.0%
2008	1,920,777	1.2%	1,036,251	-0.4%	3,550,363	-0.2%	2,240,707	-4.9%	37,945	1.1%	8,786,043	-1.2%
2009	1,864,123	-2.9%	1,018,853	-1.7%	3,463,128	-2.5%	1,935,704	-13.6%	37,933	0.0%	8,319,741	-5.3%
2010	1,927,194	3.4%	1,049,097	3.0%	3,513,428	1.5%	1,707,096	-11.8%	38,122	0.5%	8,234,937	-1.0%
2011	1,944,406	0.9%	1,058,871	0.9%	3,496,919	-0.5%	1,812,838	6.2%	36,773	-3.5%	8,349,807	1.4%
2012	1,920,496	-1.2%	1,031,590	-2.6%	3,440,945	-1.6%	1,906,607	5.2%	36,684	-0.2%	8,336,323	-0.2%
2013	1,934,121	0.7%	1,063,360	3.1%	3,431,537	-0.3%	1,819,938	-4.5%	36,338	-0.9%	8,285,294	-0.6%

Estimation Results

Ordinary Least Squares (linear regression) was used to calculate the statistical relationship between electric energy sales to each customer class and a set of explanatory variables. These relationships, in the form of equations, are then used in conjunction with forecasts of the explanatory variables to create the ultimate sales forecasts. Appendix D to this chapter titled "Estimated Sales Equations" contains the statistical reports for each of the linear regressions that are used as forecasting equations.

A truism of demand theory is that consumers respond to changes in the real price of a commodity by changing the amount of that commodity they consume. Each equation contains a price term, which is explained more completely in the earlier section titled "Prices".

Other terms included in the sales equations are the weather, number of customers, a proxy measure of household income and a number of seasonal and accounting dummy variables.

Weather and number of customers enter the sales equations as an interactive term, degree-days multiplied by customers. Degree days is either heating or cooling degree-days, taken as the positive difference between the average daily temperature and 65 degrees Fahrenheit for a cooling degree-day, and the opposite for a heating degree-day. Using it in the interaction term interprets the degree-days metric as a proxy variable for the probability that any particular space conditioning appliance will be turned on.

For example, in the equation for residential non space heating sales in Appendix D, the estimated coefficient for the interaction term between heating degree-days and customers is 0.001334. This estimated value indicates that for the typical residential non electric space heat household, an extra heating degree-day will cause the household to consume an additional 305 kWh. The same estimated coefficient for the residential electric space heat class is 0.001334, indicating that an additional heating degree-day causes a residential electric heat customer to increase its consumption by 1,334 kWh.

Employment is included in the sales equations. In the commercial and industrial equations it serves as a measure of local economic activity. More people employed means that more people will be working in air conditioned or heated spaces, or operating electricity consuming machinery and equipment. In the residential equations employment serves as a proxy for customers. The customer variable was already used in two interaction terms with weather to approximate the cooling and heating loads. Including the employment variable accounts for the growth in non-weather sensitive demand, using a variable that trends with the customer variable but is not so highly correlated with customers.

Real personal disposable income per employee is also included, as a proxy for household income. As household income rises, households will consume more of all normal commodities, including electricity.

The sales equations also contain accounting dummy variables. These variables have names like DEC99 or MAR00, signifying December 1999 or March 2000. These variables are used to remove the effect of outlying data resulting from billing adjustments and similar causes of extreme outlying data. By including a variable coded "1" in that month and zero elsewhere the effect of that month is removed from the analysis while still maintaining the continuity of the data.

The interpretation of the parameter on a dummy variable or additive combination of monthly dummy variables is that the intercept term for the equation being estimated will change by the amount of the parameter estimate for the dummy variable. In other words, if the parameter estimate for JAN is 100, the intercept term for all observations corresponding to the month of January will be 100 higher than just the estimated intercept term.

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VII. DPL DE Customer Forecast

Introduction

One of the most important activities in the Electricity and Electricity Peak Load Forecast System is customer modeling and forecasting. The electric sub models estimate and forecast customers for the commercial and residential classes (residential non-space heating and residential space heating). The customer sub model does not deal with the industrial customer class. DPL believes the number of industrial customers is not helpful to either electric because there is so much variation in size among the industrial customers.

The DPL customer model contains four customer equations:

- Electric Non Space Heat Residential Customers
- Electric Space Heat Residential Customers
- Electric Commercial Customers
- Electric Street Light Customers

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Table VII.1 reports the number of DPL DE electric customers by year from 2001 through 2013. Prior to the beginning of the Great Recession, residential customers grew at approximately 1.5% annually. Since 2008 residential customer growth has slowed, and growth was only 0.8% in 2013. A fairly constant percentage of residential customers, 28%, are on a space heat tariff. Finally, about 8 residential electric customers are needed to support each commercial electric customer, although this ratio has been falling slowly over the past decade.

Table VII.1

DPL DE Historical Electric Customers

	Residential Non Space Heat Customers	Growth (%)	Residential Space Heat Customers	Growth (%)	Commercial Customers	Growth (%)	Industrial Customers	Growth (%)	Public Street Light Customers	Growth (%)	Total Customers	Growth (%)
2001	179,349		65,486		28,909		300		314		274,358	
2002	181,678	1.3%	66,598	1.7%	29,567	2.3%	289	-3.7%	318	1.3%	278,450	1.5%
2003	184,021	1.3%	68,073	2.2%	30,167	2.0%	283	-2 1%	321	0.9%	282,865	1.6%
2004	186,002	1.1%	69,720	2.4%	30,755	1.9%	275	-2.8%	334	4.0%	287,086	1.5%
2005	189,217	1.7%	70,660	1.3%	31,328	1.9%	271	-1.5%	358	7.2%	291,834	1.7%
2006	191,477	1.2%	71,207	0.8%	31,933	1.9%	270	-0.4%	359	0.3%	295,246	1.2%
2007	193,191	0.9%	71,811	0.8%	32,410	1.5%	261	-3.3%	366	1.9%	298,039	0 9%
2008	192,699	-0.3%	72,541	1.0%	32,702	0.9%	259	-0.8%	367	0.3%	298,568	0.2%
2009	192,578	-0.1%	73,017	0.7%	32,968	0.8%	250	-3.5%	370	0.8%	299,183	0 2%
2010	192,984	0.2%	74,219	1.6%	33,111	0.4%	210	-16.0%	374	1.1%	300,898	0.6%
2011	192,891	0.0%	74,769	0.7%	33,376	0.8%	240	14.3%	370	-1 1%	301,646	0.2%
2012	193,197	0.2%	75,507	1.0%	33,577	0.6%	229	-4.6%	370	0.0%	302,880	0 4%
2013	194,415	0.6%	76,417	1.2%	33,755	0.5%	231	0.8%	368	-0.5%	305,185	0.8%

The model depends upon forecasts of service area economic variables to forecast customers. The approach to customer modeling is to assume that the number of new customers depends upon changes economic activity in the electric service territories.

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DPL finds that the most significant determinant of customers is nonfarm agricultural employment, published by the US Bureau of Labor Statistics. The relationship exists because both household formation and in migration occur more frequently when jobs are available.

Each of the customer equations contains a number of monthly dummy variables, also known as seasonal variables. These variables have names like JAN, FEB, MAR, etc. They are used to account for regularly occurring seasonality in customer formation that is not accounted for by the explanatory variables.

These dummy variables are explanatory variables intended to capture variations in demand that are not already captured by the other explanatory variables in the model. The seasonal dummy variable corresponding to each month takes the form of a monthly variable represented by a column consisting only of ones and zeros. The observations corresponding to the month that the dummy variable represents is always a one, all others are zeros. For example, the dummy variable for the month of January, takes a value of one for every January, and zero for all other months.

Several equations also contain accounting dummy variables. These variables have names like DEC99 or MAR00, signifying December 1999 or March 2000. These variables are used to remove the effect of outlying data resulting from billing adjustments and similar causes of extreme outlying data. By including a variable coded "1" in that month and zero elsewhere the effect of that month is removed from the analysis while still maintaining the continuity of the data.

The interpretation of the parameter on a dummy variable or additive combination of monthly dummy variables is that the intercept term for the equation being estimated will change by the amount of the parameter estimate for the dummy variable. In other words, if the parameter estimate for JAN is 100, the intercept term for all observations corresponding to the month of January will be 100 higher than just the estimated intercept term.

The electricity component of the customer model contains four equations. Each of the four equations corresponds to a revenue class: residential non-space heating, space heating, commercial and street light. As noted above, DPL does not forecast the number of industrial customers. The results for each of the regression equations appear as Appendix E to this chapter.

As an example, consider the first equation, RESCUSDE, residential non space heat customers within the DPL DE jurisdiction. The regression equation is estimated using monthly data from May 1991 through November 2013.

The regression contains one economic variable, the sum of total non-farm employment in the metropolitan statistical areas of Wilmington and Dover, lagged 3 months. Employment is the measure of local economic activity that we know with the most precision. Because employers must file Employment Security Form number 202 monthly – their unemployment insurance premium – the monthly employment data that we have is the nearest thing to a monthly census of employed people. The lag of six months indicates the approximate amount of time before new hiring translates into new residential non space heat customers. Finally, the estimated coefficient of 10.38423 indicates that for every 1,000 new employees hired in the Wilmington and Dover MSAs, DPL DE will add 10.4 residential non space heat customers. Note that the second equation, for residential space heat customers, reports that for every 1,000 new jobs DPL DE also gets 6.4 residential space heat customers. In other words, every 1,000 jobs eventually turns into 17 net new residential customers.

VIII. DPL DE Load Forecast

Introduction

Accompanying the retail energy and customer sub models are models which forecast electricity demand and energy usage at the zonal level (Peak Demand, Net System Output) and retail energy before losses are removed (Gross Retail Output.) Included in Appendix F is Eviews model output documenting the econometric estimates of the relationship between each electricity concept and independent variables deemed theoretically and empirically appropriate.

The three models share similar features modeled as functions of prices, weather, economics, and monthly and accounting dummy variables. Each equation contains an autoregressive term. The differences among the models lie in the appropriate jurisdictional level of variable specification.

Table VIII.1 presents the outlook for energy throughput in the Company's Delaware retail jurisdiction. Weather conditions (heating and cooling degree days) are reported in the Wilmington HDD and CDD columns. The next column, Calendar Month Retail Sales contains annual energy on a Calendar Month basis.

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Table VIII.1

DPL Delaware Energy Throughput

	Wilmington HDD	Wilmington CDD	Calendar Retail Sales (gWh)	Growth (%)
2001				
2002	4,475	1,300	9,452	
2003	5,229	1,003	9,313	-1.5%
2004	4,911	1,034	9,014	-3.2%
2005	4,946	1,286	9,233	2.4%
2006	4,372	1,135	8,709	-5.7%
2007	4,619	1,369	8,856	1.7%
2008	4,590	1,170	8,767	-1.0%
2009	4,760	988	8,319	-5.1%
2010	4,642	1,503	8,471	1.8%
2011	4,654	1,403	8,358	-1.3%
2012	4,076	1,357	8,440	1.0%
2013	4,658	1,216	8,210	-2.7%
2014	4,744	1,172	8,132	-0.9%
2015	4,744	1,172	8,189	0.7%
2016	4,744	1,172	8,221	0.4%
2017	4,744	1,172	8,236	0.2%
2018	4,744	1,172	8,216	-0.2%
2019	4,744	1,172	8,204	-0.1%
2020	4,744	1,172	8,192	-0.1%
2021	4,744	1,172	8,188	-0.1%
2022	4,744	1,172	8,197	0.1%
2023	4,744	1,172	8,214	0.2%
2024	4,744	1,172	8,234	0.2%

Table VIII.2 presents how the energy forecast appears after it is rolled up to the Delmarva zone. Weather conditions (heating and cooling degree days) are reported in the Wilmington HDD and CDD columns. The next column, Calendar Month Retail Sales contains annual energy on a Calendar Month basis for the DPL retail jurisdictions in Delaware and Maryland.

Table VIII.2

Delmarva Zone Energy Throughput

	Wilmington HDD	Wilmington CDD	Calendar Retail Sales (gWh)	Growth (%)
2001				
2002	4,475	1,300	13,620	
2003	5,229	1,003	13,607	-0.1%
2004	4,911	1,034	13,478	-0.9%
2005	4,946	1,286	13,684	1.5%
2006	4,372	1,135	13,058	-4.6%
2007	4,619	1,369	13,262	1.6%
2008	4,590	1,170	13,015	-1.9%
2009	4,760	988	12,494	-4.0%
2010	4,642	1,503	12,853	2.9%
2011	4,654	1,403	12,688	-1.3%
2012	4,076	1,357	12,354	-2.6%
2013	4,658	1,216	12,445	0.7%
2014	4,744	1,172	12,377	-0.5%
2015	4,744	1,172	12,422	0.4%
2016	4,744	1,172	12,447	0.2%
2017	4,744	1,172	12,459	0.1%
2018	4,744	1,172	12,423	-0.3%
2019	4,744	1,172	12,372	-0.4%
2020	4,744	1,172	12,321	-0.4%
2021	4,744	1,172	12,292	-0.2%
2022	4,744	1,172	12,294	0.0%
2023	4,744	1,172	12,315	0.2%
2024	4,744	1,172	12,341	0.2%

As shown in Table VIII.3, the 2013 actual summer metered peak demand on the Delmarva Zone was 3,997 MW on July 18, 2013 at 5:00 PM. At the time of the peak demand there were 29 observed cooling degrees, as the ambient dry bulb temperature was 94 degrees Fahrenheit. The official weather normalized metered demand in the Delmarva Zone for the summer of 2013 was 4,130 MW. There were no restrictions at the time of the 2013 peak, yielding an unrestricted weather normalized load of 4,130 MW.

Table VIII.3

Delmarva Zone Summer Peak Demand

	Peak Date & Hour	WLM Cooling Degrees	Metered Non-Coincident (MW)	WN Metered Non-Coincident (MW)	Growth (%)	WN Unrestricted Non-Coincident (MW)	Growth (%)
2001	8/9/01 3:00 PM	24	3,611	3,537		3,709	
2002	7/29/02 4:00 PM	29	3,758	3,680	4.0%	3,827	3.2%
2003	8/22/03 5:00 PM	26	3,670	3,801	3.3%	3,811	-0.4%
2004	8/20/04 4:00 PM	21	3,636	3,805	0.1%	3,810	0.0%
2005	7/27/05 5:00 PM	29	4,174	4,010	5.4%	4,070	6.8%
2006	8/3/06 5:00 PM	29	4,288	4,060	1.3%	4,100	0.7%
2007	8/8/07 5:00 PM	30	4,178	3,973	-2.2%	4,130	0.7%
2008	6/10/08 5:00 PM	27	3,971	3,986	0.3%	4,010	-2.9%
2009	8/21/09 3:00 PM	13	3,843	3,960	-0.6%	3,960	-1.2%
2010	7/23/10 5:00 PM	28	4,056	4,018	1.5%	4,050	2.3%
2011	7/22/11 5:00 PM	32	4,222	3,974	-1.1%	4,070	0.5%
2012	7/18/12 3:00 PM	29	4.122	4,073	2.5%	4,110	1.0%
2013	7/18/13 5:00 PM	29	3,997	4,130	1.4%	4,130	0.5%
2014		29		4,186	1.4%	4,186	1.4%
2015		29		4,287	2.4%	4,287	2.4%
2016		29		4,358	1.7%	4,358	1.7%
2017		29		4,447	2.0%	4,447	2.0%
2018		29		4,526	1.8%	4,526	1.8%
2019		29		4,595	1.5%	4,595	1.5%
2020		29		4,657	1.4%	4,657	1.4%
2021		29		4,708	1.1%	4,708	1.1%
2022		29		4,756	1.0%	4,756	1.0%
2023		29		4,806	1.1%	[illegible]	1.1%
2024		29		[illegible]	[illegible]	[illegible]	1.1%

Table VIII.4 provides winter peak demand information for the Delmarva Zone. For the 2012/13 winter heating season, the actual zone peak of 3,406MW occurred on January, 23 2013 at 8:00 AM. The weather normalized winter load was 3,370 MW.

Table VIII.4

Delmarva Zone Winter Peak Demand

	Peak Date & Hour	WLM MWHD	Metered Non-Coincident (MW)	WN Metered Non-Coincident (MW)	Growth (%)
2000/01	12/28/00 7:00 PM	41	2,917	3,088	
2001/02	2/5/02 8:00 AM	46	2,875	2,892	-6.3%
2002/03	1/24/03 8:00 AM	53	3,413	3,083	6.6%
2003/04	1/16/04 8:00 AM	55	3,398	3,122	1.3%
2004/05	1/28/05 8:00 AM	64	3,486	3,240	3.8%
2005/06	12/14/05 7:00 PM	43	3,180	3,180	-1.9%
2006/07	2/6/07 8:00 AM	55	3,603	3,360	5.7%
2007/08	2/11/08 8:00 AM	52	3,224	3,310	-1.5%
2008/09	1/16/09 7:00 PM	52	3,483	3,310	0.0%
2009/10	1/30/10 7:00 PM	47	3,313	3,350	1.2%
2010/11	1/24/11 8:00 AM	55	3,385	3,350	0.0%
2011/12	1/4/12 8:00 AM	51	3,221	3,360	0.3%
2012/13	1/23/13 8:00 AM	52	3,406	3,370	0.3%
2013/14		[illegible]		[illegible]	[illegible]
2014/15		[illegible]		[illegible]	[illegible]
2015/16		[illegible]		[illegible]	[illegible]
2016/17		[illegible]		[illegible]	[illegible]
2017/18		[illegible]		[illegible]	[illegible]
2018/19		[illegible]		[illegible]	[illegible]
2019/20		[illegible]		[illegible]	[illegible]
2020/21		[illegible]		[illegible]	[illegible]
2021/22		[illegible]		[illegible]	[illegible]
2022/23		[illegible]		[illegible]	[illegible]
2023/24		[illegible]		[illegible]	[illegible]

Disaggregated Forecasts for SOS and Choice Customers.

Projections of the demand requirements by state or jurisdiction, or by SOS and Choice customers, or by rate class, are calculated in a spreadsheet model that uses sharing techniques. Projections of energy requirements broken down by SOS and Choice customers or by rate class are also calculated in the same spreadsheet model. Results are presented in Tables VIII.5 – VIII.8, below.

The class sharing methodology first assumes that the DE state and DPL DE retail load are a constant share of the zonal forecast over the forecast horizon. The share is determined by calculating each respective jurisdiction's contribution to the 2013 Delmarva Zone peak. For further disaggregation to the customer class level, we sum the relevant rate class peaks into the classes required for IRP modeling. After calculating the IRP class contribution to the 2013 DPL DE peak mentioned above, class forecasts are calculated as a constant share of the DPL DE forecast over the forecast horizon.

In each class, the number of customers that choose to use competitive suppliers is taken to be a constant percentage of total customers in the class. SOS customers are assumed to represent a constant share of the overall energy and demand forecasts. These shares represent class level energy migration rates consistent with the prior year's peak month. Constant shares are used for forecasting choice customers because even though the fraction of any rate class that chooses choice is extremely volatile it does not appear to have a trend over time. Logic tells us that if customers could get a better deal by choosing a competitive supplier they would make that choice, with the share quickly going to 100%. That does not happen, however. As a result, since we do not have better information and there is no obvious trend, we assume that shares will remain constant at their current level.

Table VIII.5

Summer Peak Demand Forecast Disaggregated by Rate Class

	DPL Zone Non-Coincident PHI forecast* (MW)	DE Share (MW)	DPL DE Share (MW)	DPL DE Res (MW)	DPL DE Small Com (MW)	DPL DE LC&I (MW)	DPL DE SL (MW)
2014	4,186	2,755	1,912	981	33	898	0
2015	4,287	2,821	1,957	1,005	34	919	0
2016	4,358	2,869	1,990	1,021	34	935	0
2017	4,447	2,927	2,031	1,042	35	954	0
2018	4,526	2,979	2,067	1,061	35	971	0
2019	4,595	3,024	2,098	1,077	36	985	0
2020	4,657	3,066	2,127	1,092	36	999	0
2021	4,708	3,099	2,150	1,103	37	1,010	0
2022	4,756	3,131	2,172	1,115	37	1,020	0
2023	4,806	3,164	2,195	1,126	38	1,031	0
2024	4,861	3,200	2,220	1,139	38	1,042	0

*DPL MW forecast is unrestricted peak non-coincident with PJM Zonal Peak Demand
*DPL MW forecast does not include EE/DSM programs

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Table VIII.6

Summer Peak Demand Forecast Disaggregated by SOS

	DPL DE SOS Res (MW)	DPL DE SOS Small Com (MW)	DPL DE SOS LC&I (MW)	DPL DE SOS SL (MW)	DPL DE Non-SOS Res (MW)	DPL DE Non-SOS Small Com (MW)	DPL DE Non-SOS LC&I (MW)	DPL DE Non-SOS SL (MW)
2014	884	25	138	0	97	8	759	0
2015	905	25	142	0	99	8	778	0
2016	920	26	144	0	101	8	791	0
2017	939	26	147	0	103	8	807	0
2018	956	27	150	0	105	9	821	0
2019	970	27	152	0	107	9	833	0
2020	984	28	154	0	108	9	845	0
2021	994	28	156	0	109	9	854	0
2022	1,004	28	157	0	110	9	863	0
2023	1,015	28	159	0	111	9	872	0
2024	1,027	29	161	0	113	9	882	0

*DPL MW forecast is unrestricted peak non-coincident with PJM Zonal Peak Demand
*DPL MW forecast does not include EE/DSM programs

Table VIII.7

Energy Forecast Disaggregated by Rate Class

	DPL DE RES (MWh)	DPL DE COM (MWh)	DPL DE IND (MWh)	DPL DE Sm COM (MWh)	DPL DE LC&I (MWh)	DPL DE SL (MWh)
2014	3,005,454	3,474,960	1,614,764	179,265	4,910,459	36,952
2015	3,028,874	3,480,325	1,642,846	180,443	4,942,728	37,095
2016	3,037,553	3,468,340	1,678,004	181,259	4,965,085	37,161
2017	3,049,451	3,462,412	1,687,272	181,377	4,968,306	37,218
2018	3,054,383	3,457,050	1,664,985	180,403	4,941,631	37,250
2019	3,046,945	3,449,388	1,667,285	180,214	4,936,459	37,250
2020	3,033,422	3,443,097	1,676,490	180,317	4,939,270	37,230
2021	3,024,651	3,440,606	1,685,158	180,535	4,945,230	37,219
2022	3,023,941	3,442,030	1,693,792	180,889	4,954,933	37,223
2023	3,029,497	3,445,543	1,702,474	181,318	4,966,698	37,242
2024	3,036,402	3,449,385	1,711,388	181,768	4,979,006	37,263

Table VIII.8

Energy Forecast Disaggregated by SOS

	DPL DE SOS RES (MWh)	DPL DE SOS Sm COM (MWh)	DPL DE SOS LC&I (MWh)	DPL DE SOS SL (MWh)	DPL DE Non-SOS RES (MWh)	DPL DE Non-SOS Sm COM (MWh)	DPL DE Non-SOS LC&I (MWh)	DPL DE Non-SOS SL (MWh)
2014	2,708,020	135,727	756,878	26,433	297,433	43,538	4,153,581	10,520
2015	2,729,123	136,619	761,852	26,534	299,751	43,825	4,180,876	10,560
2016	2,736,943	137,237	765,298	26,582	300,610	44,023	4,199,787	10,579
2017	2,747,663	137,326	765,794	26,623	301,788	44,051	4,202,512	10,595
2018	2,752,107	136,588	761,683	26,646	302,276	43,815	4,179,948	10,604
2019	2,745,405	136,445	760,885	26,646	301,540	43,769	4,175,573	10,604
2020	2,733,221	136,523	761,319	26,632	300,201	43,794	4,177,951	10,599
2021	2,725,318	136,688	762,238	26,623	299,333	43,847	4,182,993	10,595
2022	2,724,678	136,956	763,733	26,626	299,263	43,933	4,191,200	10,597
2023	2,729,684	137,281	765,547	26,640	299,813	44,037	4,201,152	10,602
2024	2,735,906	137,621	767,444	26,655	300,496	44,146	4,211,562	10,608

IX. DPL DE IRP Forecast Scenarios

Figure IX.1 (below) presents the Company's forecast for the unrestricted summer peak demand for DPL DE jurisdiction within the Delmarva Zone, including all of the scenarios. The heavy green line is the **Baseline Scenario**; it is assumed that 50% of the possible future outcomes will be above this line and 50% will be below. The red and blue lines are the **High** and **Low**, respectively, **Economic Scenarios**. It is assumed that 10% of the possible outcomes will lie above the red line, and 10% will lie below the blue line. Finally, the purple line represents the **Extreme Weather Scenario**. Extreme Weather is represented by calculating the average and standard deviation of heating and cooling degree-days for each month of the year. In the forecast, monthly heating and cooling degree-days are set equal to their historical average plus two standard deviations.

Figure IX.1

DPL Delaware Jurisdictional Summer Peak Demand

(MW)

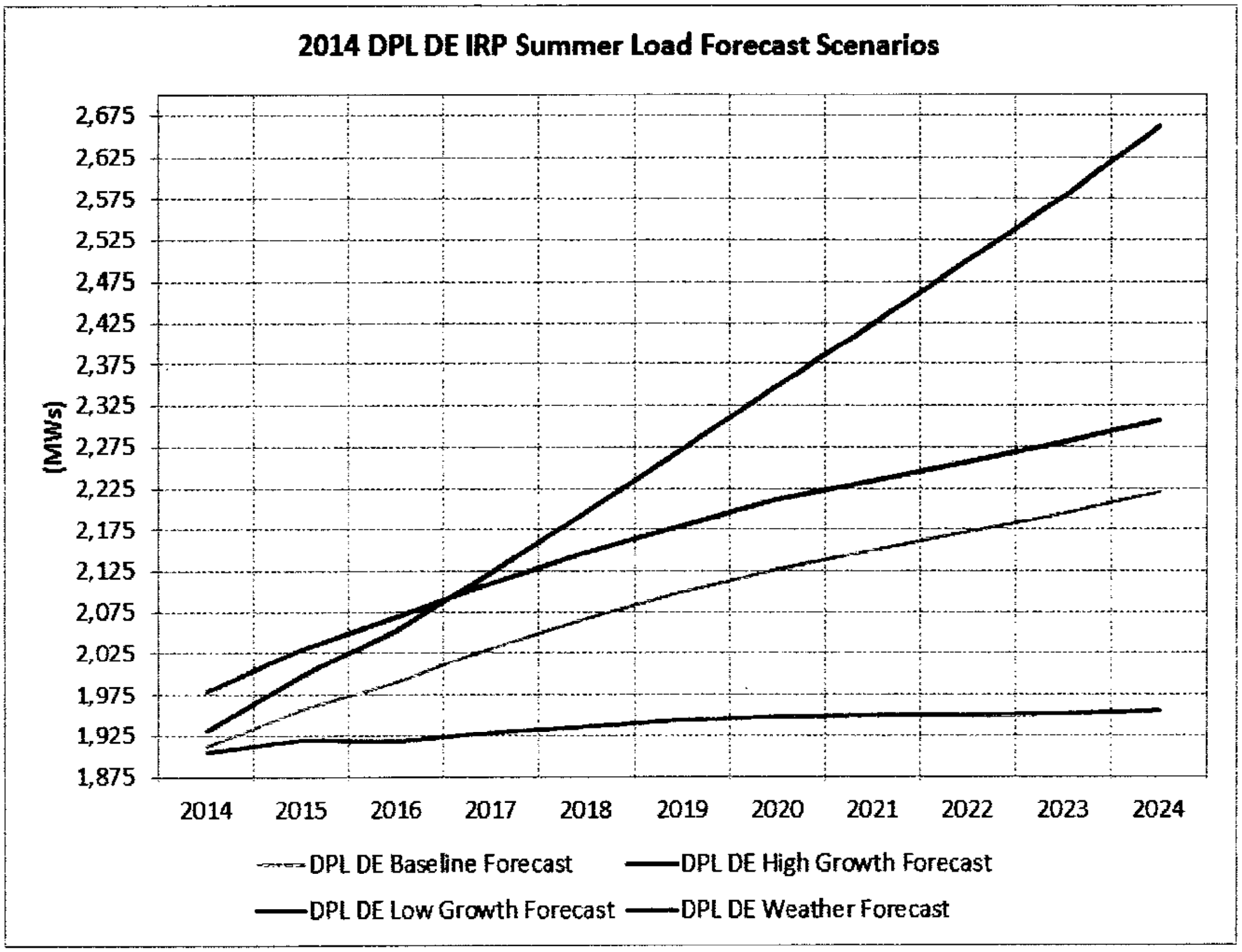
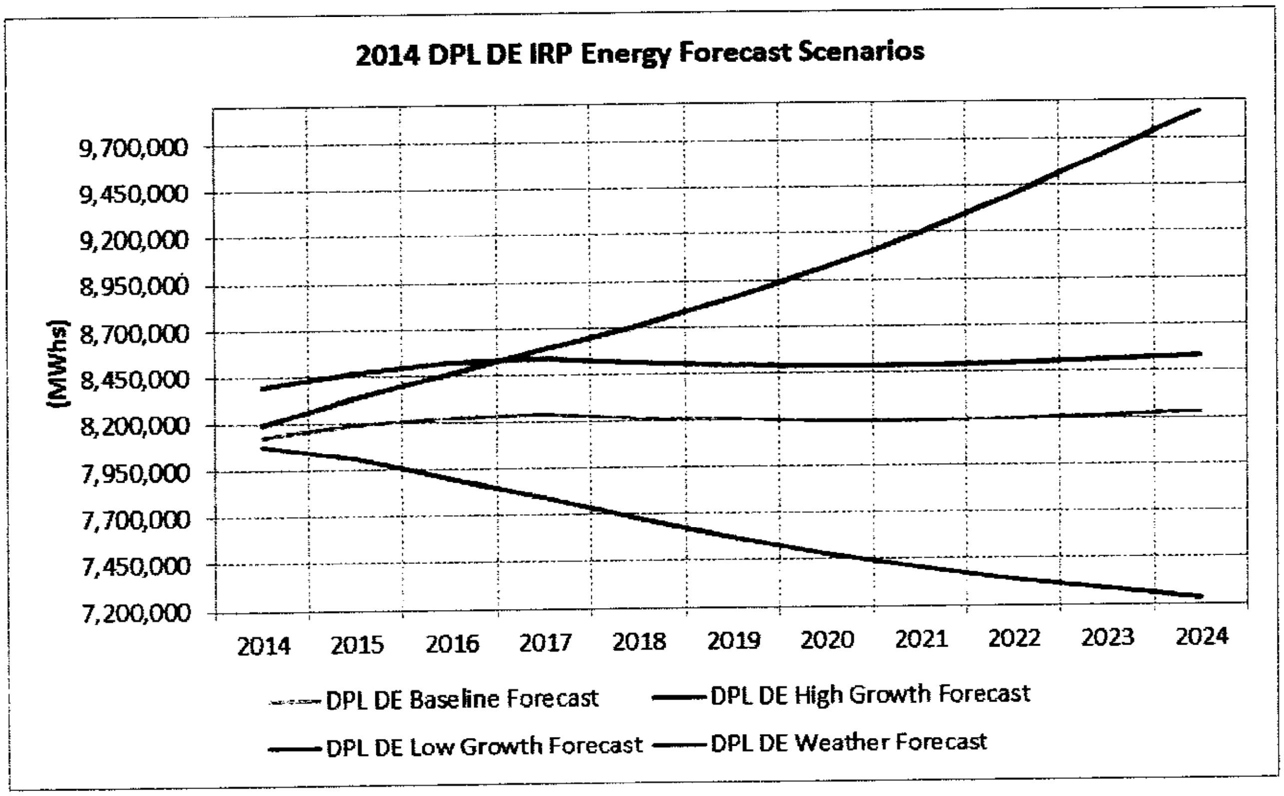


Figure IX.2 (below) illustrates energy throughput for the DPL DE jurisdiction within the Delmarva Zone, the amount of annual energy required to serve all DPL DE customers, inclusive of all losses and self-use, for these same four scenarios.

Figure IX.2

DPL DE Jurisdictional Energy Throughput

(MWh)

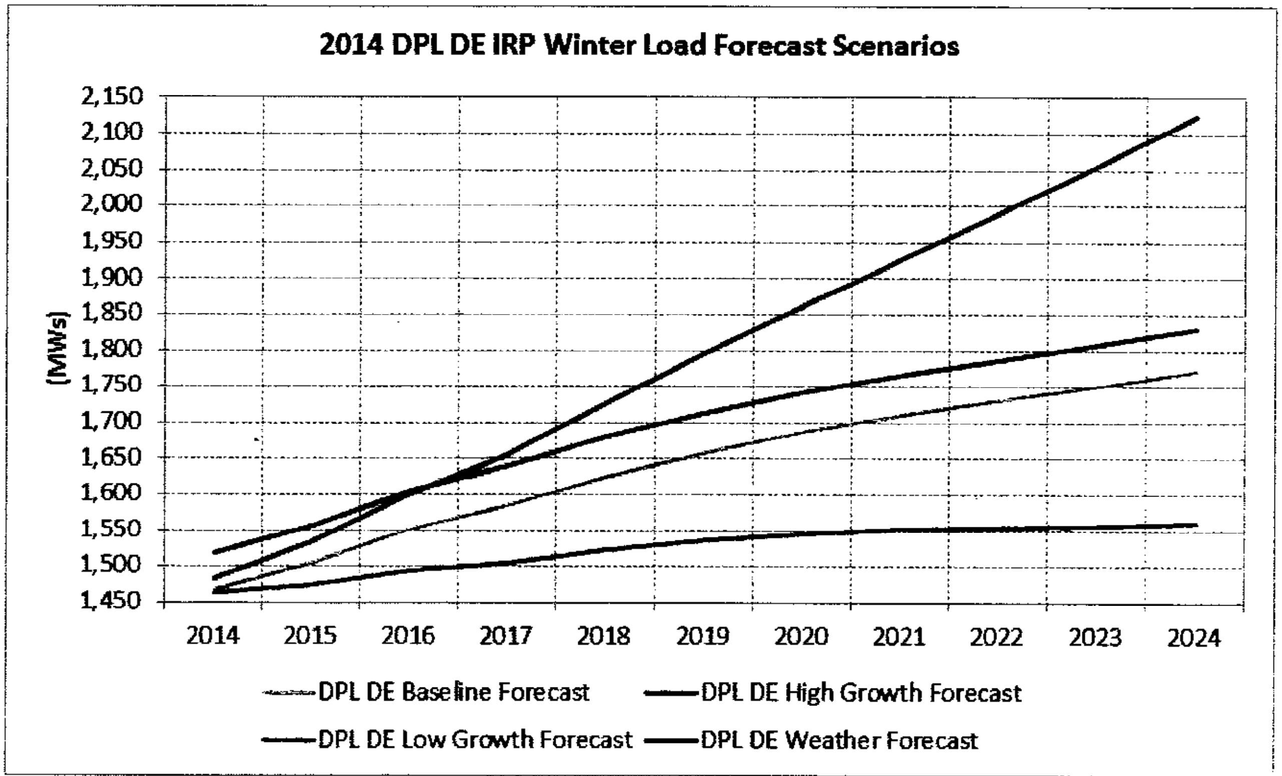


Finally, Figure IX.3 displays the DPL DE unrestricted winter peak forecast for each of the scenarios. These scenarios are constructed symmetrically to the ones provided in Figure IX.1.

Figure IX.6

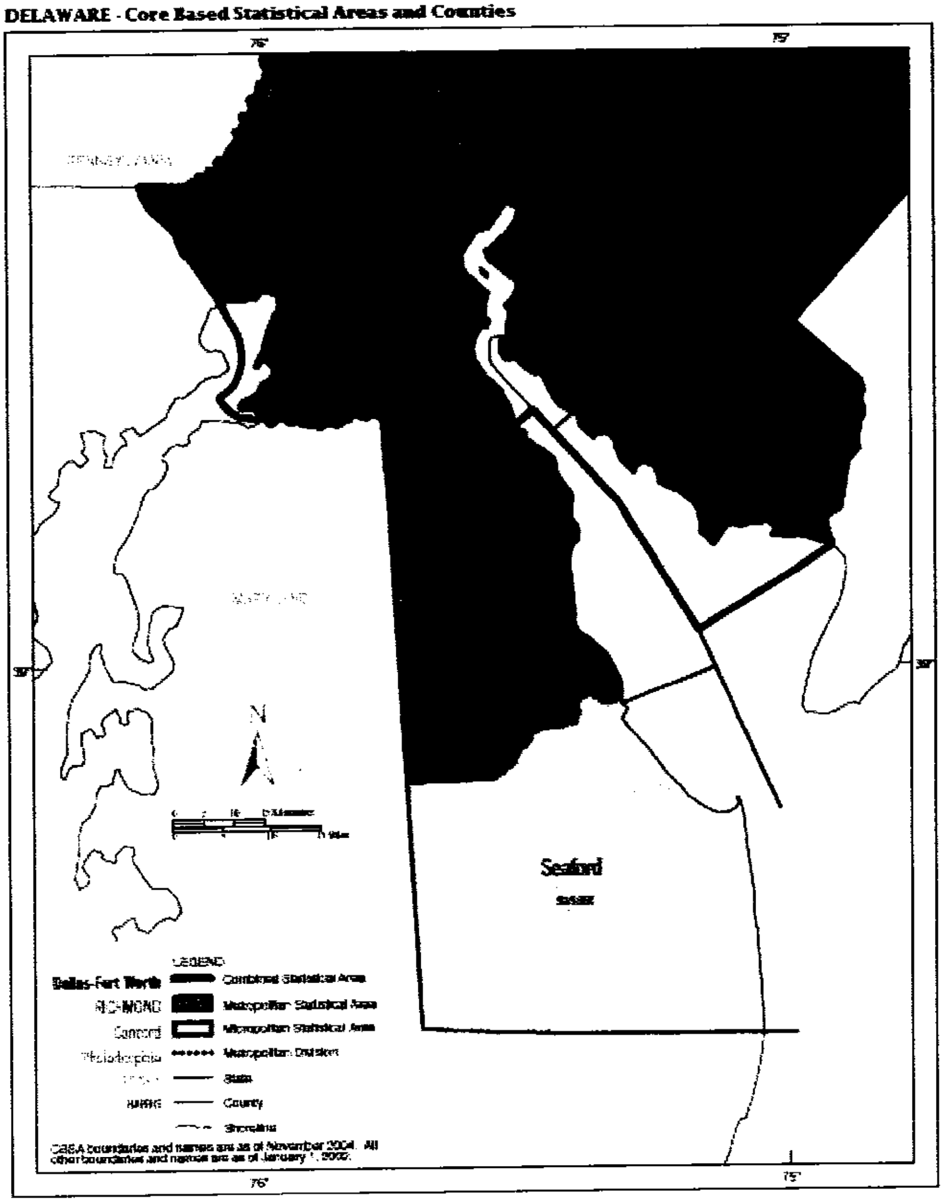
DPL Delaware Jurisdictional Winter Peak Demand

(MW)



Appendix A: Delaware Metropolitan Statistical Areas Map

DELAWARE - Core Based Statistical Areas and Counties



U.S. DEPARTMENT OF COMMERCE Economics and Statistics Administration U.S. Census Bureau

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Appendix B: IHS Global Insight Delaware Economic Reports

Delaware

Analysis: At a Glance

Payrolls continue to improve in 2014

Labor market conditions improved in May as the state economy continued to gain momentum behind robust growth in the private services sectors. The unemployment rate ticked up to 5.9% as labor force participation surged this month; however, the labor market maintained robust levels of growth and expanded 2.3% year on year (y/y). Professional/business services continued to be a bastion for growth, and expanded payrolls by 5.9% y/y this month. Financial (3.7%), leisure/hospitality (3.1%), and education/health (1.3%) all also provided solid year-on-year growth, expanding on the positive gains experienced in the latter half of 2013. The government sector even saw positive growth at both the federal and state/local levels of employment, expanding 0.5% y/y amid tight federal and state budgets.

Private services as important as ever

Between the first quarters of 2008 and 2010, when nonfarm payrolls went from peak to trough, Delaware shed 32,300 jobs, an annualized 3.8% contraction over the eight quarters. By the end of 2013, only about 52% of the jobs lost because of the recession had returned, and Delaware will not get back to peak employment until the third quarter of 2015. The financial services and professional/business sectors are two of Delaware's largest, accounting for nearly 30% of the total jobs lost in the recession. The key to a return to peak employment will be recoveries within these important sectors.

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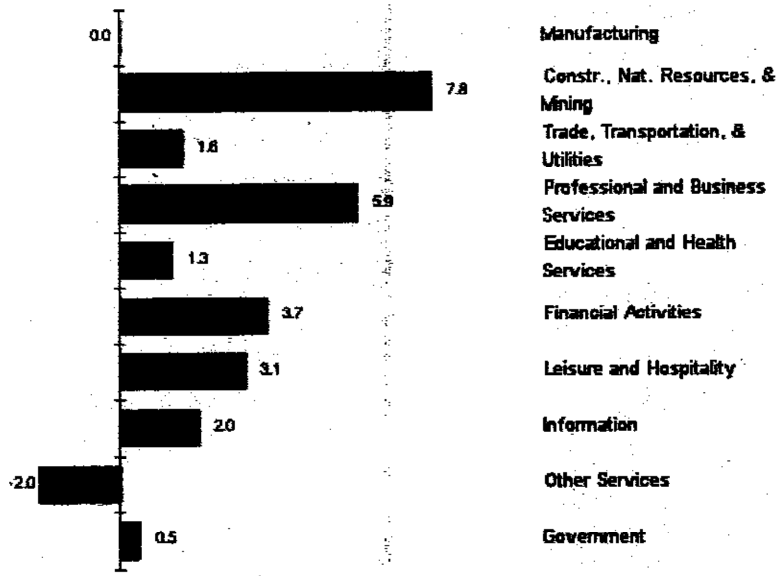
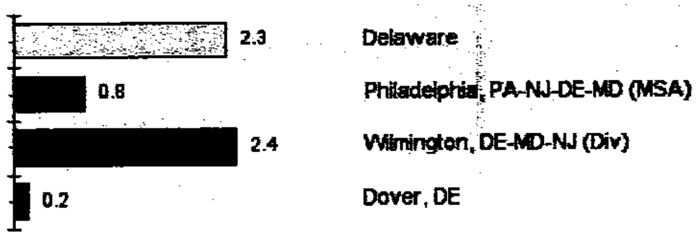
Employment by sector
(Percent change from a year earlier, May 2014)



Employment by MSA
(Percent change from a year earlier, May 2014)



Issues to watch

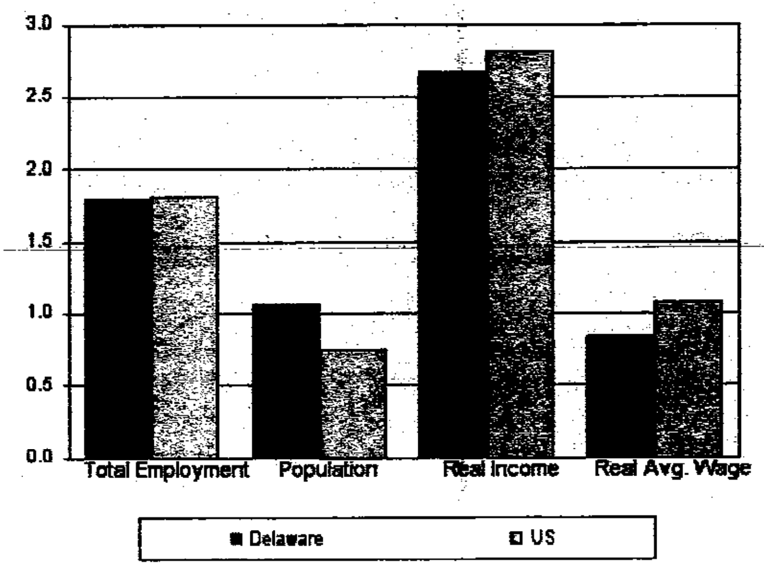
- Automatic spending cuts went into full effect on 1 March, 2013. This sequester has the ability to inflict economic pain across the region. Delaware, however receives a disproportionately smaller amount of federal dollars, relative to other neighboring states, such as Maryland. The area most likely to be affected is the large Air Force base in Dover. On the defense-end of the sequester, most will react to budget cuts not by slashing payrolls, but forcing employment furloughs, which will primarily result in lost wages. Nevertheless, outside of the sequester, federal payrolls are being trimmed and there is a downward trend after large federal injections during the Great Recession.
- The recent recession was driven by a liquidity crisis, which has caused a breakdown of several financial institutions. Financial services is one of the largest sectors in Delaware's economy; Bank of America is

the largest employer in the state's financial sector, with a payroll of about 7,000. Bank of America, which is headquartered in North Carolina, announced in September plans to cut 30,000 total jobs by 2014. It is not yet clear how this will affect the financial institution's standing in Wilmington.

- Delaware has some significant competitive advantages compared with other states, including proximity to large metro areas such as New York (New York), Philadelphia (Pennsylvania), Baltimore (Maryland), and Washington, D.C.; an above-average share of highly skilled scientific and technical workers; a critical mass of chemical, pharmaceutical, and biomedical companies; a tradition of technical innovation; high research and development spending by such companies as DuPont and AstraZeneca; modest but steady population growth; a low cost of living; and a favorable regulatory climate.

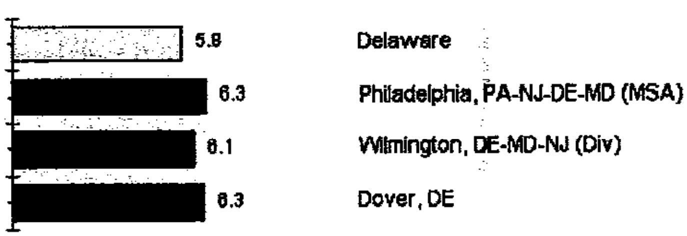
Growth Relative to the US Average

(Average annual percent change, 2013 to 2015)



Unemployment Rate by MSA

(Percent, April 2014)



Near-term developments

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In March 2013, the Bureau of Labor Statistics released a new 2013 benchmark, which provided a more accurate picture of 2013. Our outlook for 2014 remains unchanged, however. For the remainder of 2014, expect total nonfarm payrolls to remain positive and grow at a 1.7% annualized pace, while real gross state product (GSP) will pick up and grow at a similar 1.7%.

Delaware Outlook over the Next Four Quarters

		Baseline Scenario			Pessimistic			Optimistic		
		Level	Percent	Rank	Level	Percent	Rank	Level	Percent	Rank
Year-over-year Change (2015Q2)										
	Employment	+8,302	+1.9	25	+3,652	+0.8	26	+7,714	+1.8	27
	Personal Income (Mil.$)	+2,024	+4.7	19	+1,255	+2.9	20	+2,491	+5.7	18
	Real Gross State Product (Mil. 2005$)	+1,360	+2.3	40	+169	+0.3	42	+1,702	+2.9	42
Level (2015Q2)										
	Unemployment Rate (%)	5.6		31	6.6		29	5.3		30
	Housing Starts	4,519		42	3,126		42	4,905		42

Outlook

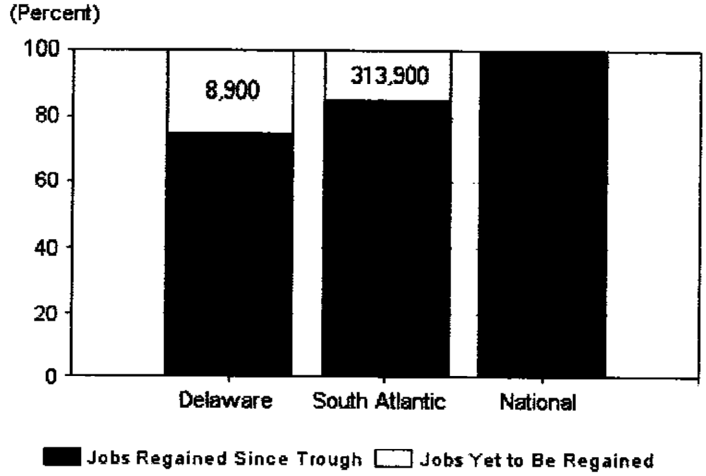
Changes to the Forecast (Short Term)

Real GSP	Lower
Employment	Unchanged
Personal Income	Lower
Unemployment Rate	Unchanged
Housing Starts	Lower

Gaining momentum

Delaware's economy picked up steam in 2013, growing at a 1.8% rate, a stark turnaround from the flat 0.3% growth posted in 2012. IHS expects continued momentum in 2014 as the economic fundamentals improve, especially in the professional business services, financial services, and construction sectors. Looking ahead, employment growth will average 1.6% annually from 2014 to 2019, while real gross state product and real personal income climb more than 2.8% and 3.6% annually, respectively, over this period. Strong levels of in-migration will continue to push state population growth at a 1.1% rate over the forecast horizon

Recession Recovery: Changes in Employment



Strengths

- Although Delaware needs to diversify its economic structure further, the increasing diversification that occurred during the late 1990s buffered the state from the pro-cyclical employment declines that it has suffered in past downturns in the manufacturing sector. The state is less dependent on a few cyclical sectors (autos, chemicals, pharmaceuticals, and financial services) that are affected by a decline in national investment.

Weaknesses

- Delaware had great success during the 1990s in attracting new financial services firms with the passage of several progressive tax and incorporation laws. Nevertheless, because of consolidation in the financial-activities sector, along with continued productivity growth driven by IT investments that are increasing the capital/labor ratio, this sector will not be as big an employment driver going forward as it was during the 1990s.

Economic Key Indicators

	2010	2011	2012	2013	2014	2015	2016	2017
Real Gross State Product (Mil. 2005 $)	56,684	56,789	57,129	57,938	59,013	60,412	62,472	64,332
Real Gross State Product (% change)	1.1	0.2	0.6	1.4	1.9	2.4	3.4	3.0
Total Employment (Thous.)	413.8	417.1	419.5	427.8	437.1	445.9	454.7	462.0
Total Employment (% change)	-0.6	0.8	0.6	2.0	2.2	2.0	2.0	1.6
Manufacturing Employment (Thous.)	25.9	25.8	25.7	25.4	25.6	26.0	26.3	26.5
Nonmanufacturing Employment (Thous.)	387.9	391.4	393.8	402.4	411.4	419.8	428.4	435.5
Population (Thous.)	900.8	909.2	918.1	926.9	936.3	946.4	956.8	967.2
Population (% change)	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1
Unemployment Rate (%)	8.0	7.4	7.1	6.7	5.8	5.5	5.5	5.4
Personal Income (% change)	1.5	5.2	4.3	3.2	4.2	4.9	5.4	5.8
U.S. ECONOMY								
Real Gross Domestic Product (% change)	2.5	1.8	2.8	1.9	1.7	3.0	3.3	3.2
Employment (% change)	-0.7	1.2	1.7	1.7	1.8	1.9	1.8	1.6

Wilmington, DE-MD-NJ

Analysis: At a Glance

Manufacturing and financial services bolster Wilmington payrolls

Wilmington payrolls continued their moderate expansion with 1.0% growth in 2013. Indeed, although the metro sector is substantially well below its prerecession peak, the unemployment rate continued to tick down and now sits at 7.3%. The metro's manufacturing employment gains remained above this average, growing 2.8% for the year, bolstered by the recent turnaround in regional manufacturing activity. Meanwhile, the influential financial services sector remained positive throughout 2013, and growth accelerated to 2.4%. In

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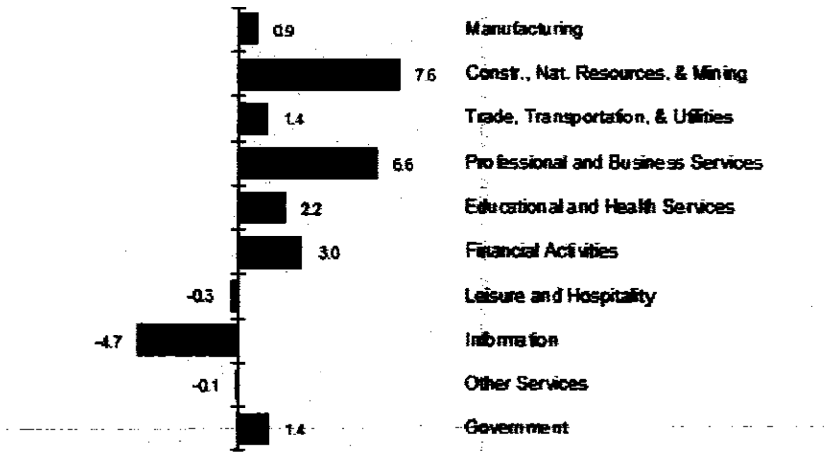
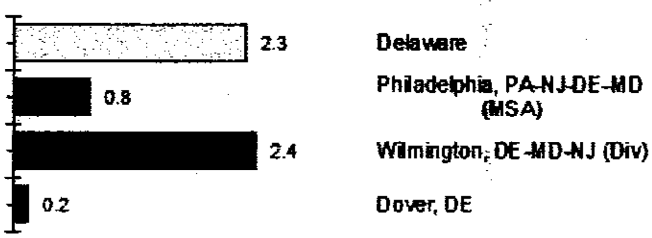
fact, the private services sectors, which have cushioned the Wilmington economy in the face of lackluster construction and manufacturing gains, continued to perform and add jobs over the prior year. Notably, professional/business (up 2.0%), education/health (up 2.4%), and "other" service sectors (up 1.0%) all posted above-average rates of growth. The metro's public sector, meanwhile, continued to show weakness in the face of automatic spending cuts at the federal level, contracting 0.1% in 2013.

Employment by sector
(Percent change from a year earlier, May 2014)



Employment by MSA
(Percent change from a year earlier, May 2014)



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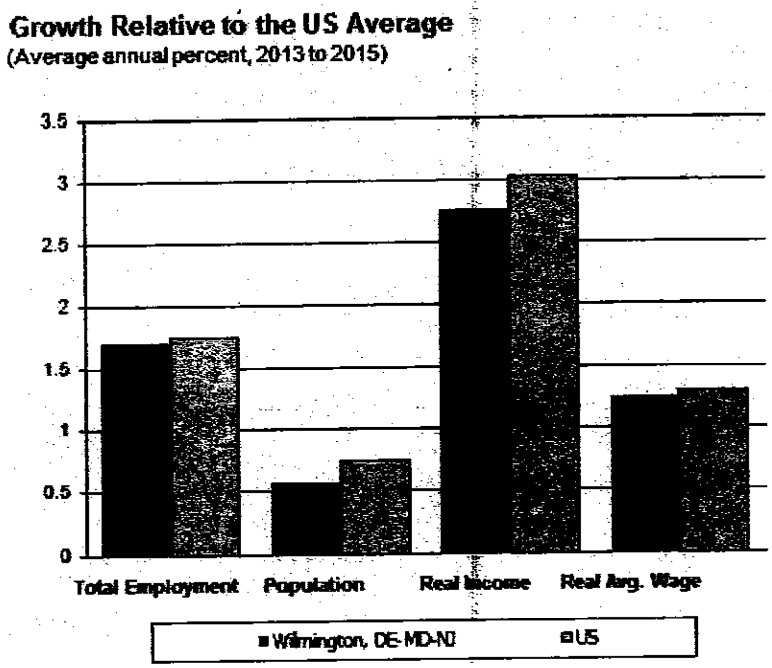

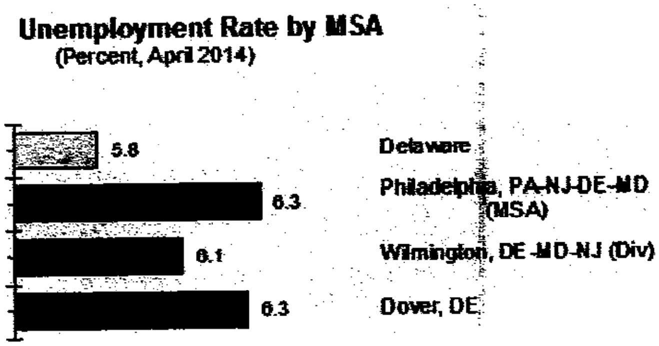

Near-term developments

The Wilmington metro ended 2013 with 1.1% y/y total payroll growth through December. This trend of moderate growth will continue into 2014, when payrolls will expand at a similar rate. The metro will pick up steam in the first quarter and grow 1.1% annualized, thanks to renewed growth from the manufacturing sector and continued increases in the influential financial and professional/business service sectors.

Outlook

Significant improvement over the next few years

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The Wilmington economy will continue its momentum, registering employment growth of 1.1% in 2014, while real gross metro product expands 1.7%. In addition to education and healthcare, the renewed growth in the manufacturing sector and professional and business services industries will help create stronger job gains. During 2014–19, we forecast Wilmington will average solid 1.5% annual employment growth. The unemployment rate, which has been stuck above 7.0% since 2008, will finally fall back below that threshold in 2014.

Economic Key Indicators

	2010	2011	2012	2013	2014	2015	2016	2017
Real Gross Metro Product (Mil. 2005 $)	50,932	51,332	52,331	53,146	54,005	55,441	57,461	59,301
Real Gross Metro Product (% change)	3.0	0.8	1.9	1.6	1.6	2.7	3.6	3.2
Total Employment (Thous.)	328.7	331.8	334.3	340.8	348.3	355.0	361.6	366.8
Total Employment (% change)	-1.2	1.0	0.7	1.9	2.2	1.9	1.9	1.4
Manufacturing Employment (Thous.)	18.2	18.5	18.6	18.4	18.6	18.8	18.9	19.0
Nonmanufacturing Employment (Thous.)	310.5	313.3	315.7	322.3	329.7	336.2	342.7	347.8
Population (Thous.)	707.5	710.5	713.9	717.2	720.8	725.6	730.5	735.8
Population (% change)	0.4	0.4	0.5	0.5	0.5	0.6	0.7	0.7
Unemployment Rate (%)	8.6	7.8	7.5	7.0	6.1	5.8	5.8	5.8
Personal Income (% change)	1.4	5.5	4.3	2.8	4.1	4.6	5.2	5.5
U.S. ECONOMY								
Real Gross Domestic Product (% change)	2.5	1.8	2.8	1.9	1.7	3.0	3.3	3.2
Employment (% change)	-0.7	1.2	1.7	1.7	1.8	1.9	1.8	1.6

Dover, DE

Analysis: At a Glance

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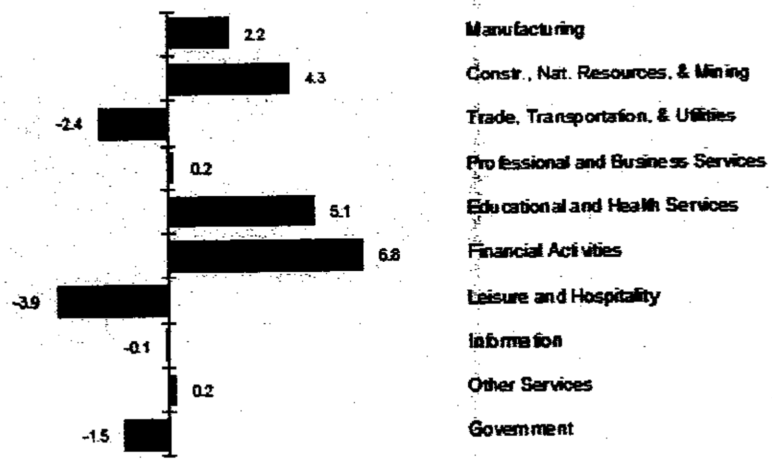
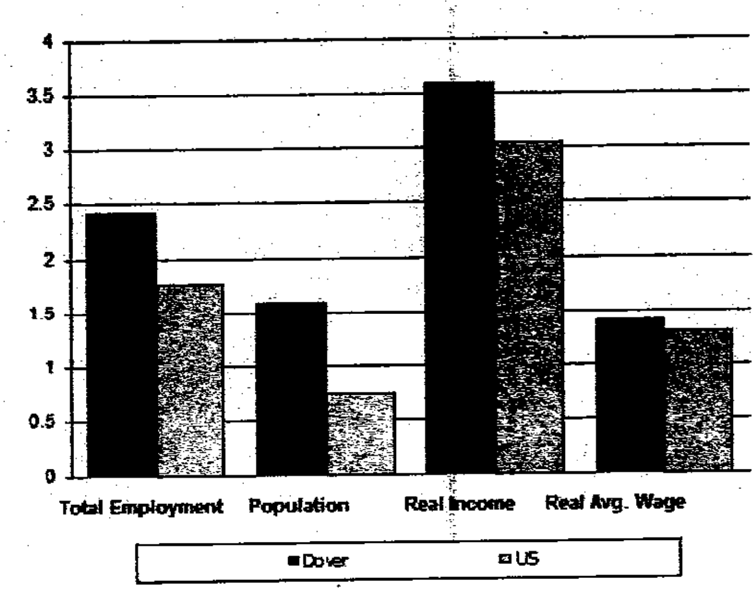
Employment by sector
(Percent change from a year earlier, April 2014)



Growth Relative to the US Average
(Average annual percent, 2013 to 2015)



Personal Income Indicators

	2010	2011	2012	2013	2014	2015	2016	2017
Per Capita Personal Income (Thous. $)	34.2	35.0	36.1	37.2	38.1	39.2	40.6	42.4
Per Capita Personal Income (% change)	0.3	2.4	3.1	2.9	2.4	3.0	3.6	4.5
Average Annual Wage (Thous. $)	36.7	37.6	39.0	39.4	40.7	41.8	43.0	44.3

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Average Annual Wage (% change)	-0.9	2.3	3.7	1.2	3.3	2.7	2.8	3.1
Total Personal Income (Mil. $)	5,579	5,799	6,060	6,310	6,551	6,858	7,208	7,638
Total Personal Income (% change)	1.8	3.9	4.5	4.1	3.8	4.6	5.2	6.0
Wage Disbursements (Mil. $)	2,533	2,581	2,697	2,788	2,903	3,029	3,180	3,343
Wage Disbursements (% change)	0.0	1.9	4.5	3.4	4.1	4.3	5.0	5.1
Nonwage Income (Mil. $)	3,046	3,218	3,363	3,523	3,648	3,823	4,028	4,295
Nonwage Income (% change)	3.4	5.7	4.5	4.7	3.6	4.8	5.4	6.6

Outlook

Economic Key Indicators

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Real Gross Metro Product (Mil. 2005 $)	5,885	5,814	5,950	6,085	6,231	6,317	6,464	6,620
Real Gross Metro Product (% change)	-5.1	-1.2	2.3	2.3	2.4	1.4	2.3	2.4
Total Employment (Thous.)	64.5	64.3	64.7	66.1	66.7	67.7	69.2	70.6
Total Employment (% change)	0.8	-0.3	0.6	2.2	0.8	1.6	2.1	2.0
Manufacturing Employment (Thous.)	4.6	4.4	4.5	4.7	4.8	4.9	4.9	4.9
Nonmanufacturing Employment (Thous.)	59.9	59.9	60.2	61.4	61.9	62.9	64.3	65.7
Population (Thous.)	163.0	165.5	167.7	169.7	172.1	174.7	177.4	180.0
Population (% change)	1.6	1.5	1.4	1.2	1.4	1.5	1.5	1.5
Unemployment Rate (%)	8.1	7.7	7.4	6.9	6.2	5.8	5.6	5.5
Personal Income (% change)	1.8	3.9	4.5	4.1	3.8	4.6	5.2	6.0
U.S. ECONOMY								
Real Gross Domestic Product (% change)	2.5	1.8	2.8	1.9	1.7	3.0	3.3	3.2
Employment (% change)	-0.7	1.2	1.7	1.7	1.8	1.9	1.8	1.6

Appendix C: WN Factor Table

DPL DE Historical WN Factors

	CDD(65)				
	2014	2013	2012	2011	2010
RES	214,279.94	233,613.40	228,962.80	228,312.60	273,369.58
RSH	65,983.25	83,928.59	75,754.91	61,019.22	103,119.37
COM	147,008.58	151,503.70	145,881.80	112,514.50	125,886.45
Total	427,271.78	469,045.69	450,599.51	401,846.32	502,375.40

	HDD(65)				
	2014	2013	2012	2011	2010
RES	48,028.90	45,654.50	31,500.99	17,490.02	20,391.77
RSH	90,561.99	63,060.85	67,575.75	83,018.04	88,453.91
COM	39,793.43	11,576.28	46,865.77	33,301.76	44,626.96
Total	178,384.31	120,291.63	145,942.51	133,809.82	153,472.64

	HDD(35)				
	2014	2013	2012	2011	2010
RES	0.00	0.00	0.00	0.00	0.00
RSH	24,026.38	55,804.64	44,834.13	0.00	0.00
COM	17,480.38	80,748.22	0.00	0.00	0.00
Total	41,506.76	136,552.86	44,834.13	0.00	0.00

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Appendix D: Estimated Sales Equations

The following regressions were estimated using the EViews econometrics software package.

DPL DE Residential Non Space Heat Electric Sales

```
==========================================================================
Dependent Variable: RESKWHDE
Method: Least Squares
Date: 01/14/14   Time: 13:42
Sample (adjusted): 1992M08 2013M11
Included observations: 256 after adjustments
Convergence achieved after 14 iterations
==========================================================================
```

Variable	CoefficienStd. Error	t-Statistic	Prob.	
C	118970.4	12714.88	9.356784	0.0000
@MOVAV(RESPRIDE(-6)/(CPIU(-6)/CPI12	-196373.6	83812.25	-2.343018	0.0199
BILLWFORTCDD65WLM*RESCUSDE	0.001705	3.74E-05	45.52097	0.0000
BILLWFORTHDD65WLM*RESCUSDE	0.000305	1.80E-05	16.94358	0.0000
JAN	9850.846	1623.097	6.069167	0.0000
FEB	-6389.765	1667.068	-3.832935	0.0002
APR	-4313.498	1519.683	-2.838420	0.0049
MAY	-5212.500	1594.269	-3.269523	0.0012

JUL	10960.16	1320.913	8.297408	0.0000
SEP	7502.489	1266.042	5.925941	0.0000
NOV	-4942.238	1275.969	-3.873322	0.0001
JUN00	24708.83	5958.332	4.146938	0.0000
AR(1)	0.881085	0.028939	30.44596	0.0000

R-squared	0.961185	Mean dependent var	142375.3
Adjusted R-squared	0.959268	S.D. dependent var	38679.03
S.E. of regression	7806.266	Akaike info criteri	20.81269
Sum squared resid	1.48E+10	Schwarz criterion	20.99272
Log likelihood	-2651.024	F-statistic	501.4530
Durbin-Watson stat	2.586077	Prob(F-statistic)	0.000000

Inverted AR Roots	.88

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DPL DE Residential Space Heat Electric Sales

==

Dependent Variable: RSHKWHDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1992M02 2013M11

Included observations: 262 after adjustments

Convergence achieved after 14 iterations

==

Variable	CoefficienStd. Error	t-Statistic	Prob.	
C	40012.78	3451.469	11.59297	0.0000
@MOVAV(RSHPRIDE/(CPIU/CPI12),1)	-88778.50	24727.74	-3.590239	0.0004
BILLWFORTCDD65WLM*RSHCUSDE	0.002366	6.80E-05	34.79764	0.0000
BILLWFORTHDD65WLM*RSHCUSDE	0.001334	3.66E-05	36.43790	0.0000
FEB00	-23148.50	4931.221	-4.694274	0.0000
JAN01	12752.45	4862.566	2.622577	0.0093
JAN	13109.12	1462.609	8.962834	0.0000
FEB	6933.270	1679.264	4.128755	0.0000
MAR	9811.817	1303.493	7.527327	0.0000
SEP	7617.994	1057.449	7.204121	0.0000
NOV	-6156.447	1047.835	-5.875396	0.0000
AR(1)	0.405433	0.060047	6.751947	0.0000

R-squared	0.964594	Mean dependent var	81609.06
Adjusted R-squared	0.963036	S.D. dependent var	26563.89
S.E. of regression	5107.187	Akaike info criteri	19.95940
Sum squared resid	6.52E+09	Schwarz criterion	20.12284
Log likelihood	-2602.682	F-statistic	619.1734
Durbin-Watson stat	2.099641	Prob(F-statistic)	0.000000

Inverted AR Roots	.41

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DPL DE Commercial Electric Sales

===

Dependent Variable: COMKWHDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1992M04 2013M11

Included observations: 260 after adjustments

Convergence achieved after 13 iterations

===

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	235121.7	17703.41	13.28115	0.0000
@MOVAV(COMPRIDE(-2)/(CPIU(-2)/CPI12	-139793.6	91357.22	-1.530187	0.1273
BILLWFORTCDD65WLM*COMCUSDE	0.006163	0.000730	8.444994	0.0000
BILLWFORTHDD65WLM*COMCUSDE	0.001409	0.000136	10.37978	0.0000
MAR00	-85725.58	7850.554	-10.91969	0.0000
MAY00	78054.31	7734.972	10.09109	0.0000
AUG00	-38236.10	9005.640	-4.245795	0.0000
OCT00	-69358.98	8076.618	-8.587626	0.0000
JUL00	60540.34	9166.897	6.604235	0.0000
JAN	12451.76	1681.505	7.405127	0.0000
MAR	7802.939	1676.385	4.654623	0.0000
JUN	15896.72	3241.360	4.904335	0.0000

JUL	19596.91	6572.122	2.981823	0.0032
AUG	11309.29	7719.055	1.465114	0.1442
SEP	28013.77	5399.244	5.188461	0.0000
OCT	17732.96	2532.137	7.003160	0.0000
AR(1)	0.955192	0.017463	54.69840	0.0000

R-squared	0.953364	Mean dependent var	256305.4
Adjusted R-squared	0.950294	S.D. dependent var	46878.16
S.E. of regression	10451.45	Akaike info criteri	21.41002
Sum squared resid	2.65E+10	Schwarz criterion	21.64283
Log likelihood	-2766.302	F-statistic	310.4753
Durbin-Watson stat	2.536634	Prob(F-statistic)	0.000000

Inverted AR Roots	.96

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DPL DE Industrial Electric Sales

Dependent Variable: INDKWHDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1992M02 2013M11

Included observations: 262 after adjustments

Convergence achieved after 7 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	152376.7	28157.34	5.411617	0.0000
@MOVAV(INDPRIDE/(CPIU/CPI12),1)	-939080.8	218257.3	-4.302632	0.0000
@MOVAV(NEMFWLM(-3)+NEMFDOV(-3),1)	3917.916	578.1062	6.777156	0.0000
CDD65WLM	56.75231	27.08320	2.095480	0.0371
DEC	33449.14	10983.06	3.045522	0.0026
AR(1)	0.224625	0.060864	3.690628	0.0003

R-squared	0.406531	Mean dependent var	221391.0
Adjusted R-squared	0.394940	S.D. dependent var	64073.77
S.E. of regression	49840.16	Akaike info criteri	24.49366
Sum squared resid	6.36E+11	Schwarz criterion	24.57538
Log likelihood	-3202.670	F-statistic	35.07247

```
Durbin-Watson stat          2.073349    Prob(F-statistic)   0.000000
=====================================================================
Inverted AR Roots                .22
=====================================================================
```

DPL DE Public Street Light Electric Sales

Dependent Variable: PSLKWHDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1992M07 2013M11

Included observations: 212 after adjustments

Convergence achieved after 10 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	2784.061	426.8802	6.521879	0.0000
@MOVAV(PSLPRIDE(-3)/(CPIU(-3)/CPI12	-1148.540	894.5877	-1.283877	0.2006
@MOVAV(PSLCUSDE(-3),3)	1.615637	1.356768	1.190798	0.2351
MAR00	1552.204	178.3109	8.705040	0.0000
FEB01	645.2811	180.9443	3.566186	0.0005
AR(1)	0.631268	0.049486	12.75648	0.0000

R-squared	0.558352	Mean dependent var	3105.176
Adjusted R-squared	0.547632	S.D. dependent var	312.1740
S.E. of regression	209.9629	Akaike info criteri	13.55963
Sum squared resid	9081394.	Schwarz criterion	13.65463
Log likelihood	-1431.321	F-statistic	52.08686

```
Durbin-Watson stat          1.836421    Prob(F-statistic)   0.000000
=========================================================================
Inverted AR Roots                 .63
=========================================================================
```

Appendix E: Customer Sub-Model Econometric Equations

Residential Non Space Heat Electric Customers

==

Dependent Variable: RESCUSDE

Method: Least Squares

Date: 01/14/14   Time: 13:42

Sample (adjusted): 1991M05 2013M11

Included observations: 271 after adjustments

Convergence achieved after 8 iterations

==

Variable	CoefficienStd. Error		t-Statistic	Prob.
C	214538.9	11843.81	18.11401	0.0000
@MOVAV(NETDOV(-3)+NETWLM(-3),1)	10.38423	2.624730	3.956303	0.0001
MAR00	7145.941	232.3687	30.75260	0.0000
FEB00	-15592.44	184.5403	-84.49342	0.0000
MAY00	-5536.318	231.9981	-23.86363	0.0000
JUN00	-626.1149	182.6007	-3.428874	0.0007
APR00	-15927.33	246.4393	-64.62981	0.0000
SEP00	-1651.990	163.9539	-10.07594	0.0000

OCT00	-803.6891	164.4998	-4.885654	0.0000
JAN	87.20304	30.43124	2.865577	0.0045
NOV	-67.70255	30.50206	-2.219606	0.0273
AR(1)	0.996544	0.000990	1006.599	0.0000

R-squared	0.999759	Mean dependent var	179117.1
Adjusted R-squared	0.999749	S.D. dependent var	12586.11
S.E. of regression	199.5904	Akaike info criteri	13.47368
Sum squared resid	10317605	Schwarz criterion	13.63318
Log likelihood	-1813.684	F-statistic	97582.04
Durbin-Watson stat	1.474944	Prob(F-statistic)	0.000000

Inverted AR Roots	1.00

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Residential Space Heat Electric Customers

Dependent Variable: RSHCUSDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1992M03 2013M11

Included observations: 261 after adjustments

Convergence achieved after 10 iterations

Variable	CoefficienStd. Error	t-Statistic	Prob.	
C	92914.61	7333.345	12.67015	0.0000
@MOVAV(NETDOV(-3)+NETWLM(-3),1)	6.384889	1.129766	5.651515	0.0000
@MOVAV(RSHPRIDE/GRSHPRICE,2)	-7503.312	10175.90	-0.737361	0.4616
FEB00	15274.80	67.53036	226.1917	0.0000
APR00	-5302.438	69.15966	-76.66951	0.0000
MAY00	-1851.903	68.89879	-26.87859	0.0000
JAN00	-473.0544	67.50948	-7.007230	0.0000
JUN	-32.67397	12.73001	-2.566689	0.0109
SEP	-51.42675	12.86507	-3.997395	0.0001
NOV	-24.52087	12.78933	-1.917292	0.0563
AR(1)	0.996925	0.000749	1331.121	0.0000

R-squared	0.999867	Mean dependent var	66110.19
Adjusted R-squared	0.999862	S.D. dependent var	7009.170
S.E. of regression	82.40281	Akaike info criteri	11.70235
Sum squared resid	1697556.	Schwarz criterion	11.85258
Log likelihood	-1516.156	F-statistic	188089.6
Durbin-Watson stat	2.212402	Prob(F-statistic)	0.000000

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Inverted AR Roots 1.00

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Commercial Electric Customers

==

Dependent Variable: COMCUSDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1991M04 2013M11

Included observations: 272 after adjustments

Convergence achieved after 9 iterations

==

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	49647.04	9013.140	5.508296	0.0000
@MOVAV(NETWLM(-2)+NETDOV(-2),1)	1.401504	0.576171	2.432446	0.0157
MAR00	3984.710	41.47540	96.07405	0.0000

MAY00	2413.538	57.60087	41.90107	0.0000
JUN00	2661.537	57.96227	45.91845	0.0000
JUL00	3078.896	52.56455	58.57363	0.0000
AUG00	3167.474	40.83303	77.57136	0.0000
APR00	499.7910	52.96015	9.437115	0.0000
JUN	19.65214	6.635095	2.961849	0.0033
OCT	-12.24950	6.590869	-1.858556	0.0642
DEC	49.97068	6.629953	7.537110	0.0000
AR(1)	0.998167	0.000767	1301.641	0.0000

R-squared	0.999850	Mean dependent var	29004.24
Adjusted R-squared	0.999844	S.D. dependent var	3517.938
S.E. of regression	43.93605	Akaike info criteri	10.44646
Sum squared resid	501898.0	Schwarz criterion	10.60554
Log likelihood	-1408.719	F-statistic	157923.1
Durbin-Watson stat	2.232498	Prob(F-statistic)	0.000000

Inverted AR Roots	1.00

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Street Light Electric Customers

```
==================================================================
Dependent Variable: PSLCUSDE
Method: Least Squares
Date: 01/14/14   Time: 13:42
Sample (adjusted): 1992M02 2013M11
Included observations: 219 after adjustments
Convergence achieved after 7 iterations
==================================================================
            Variable              CoefficienStd. Errort-Statistic  Prob.
==================================================================
                C                 358.5819   40.84825   8.778392   0.0000
@MOVAV(NETDOV(-2)+NETWLM(-2),5)   0.083178   0.080507   1.033174   0.3027
              AR(1)               0.992359   0.003177   312.3151   0.0000
==================================================================
R-squared                         0.997947   Mean dependent var 335.9543
Adjusted R-squared                0.997928   S.D. dependent var 32.83819
S.E. of regression                1.494806   Akaike info criteri3.655474
Sum squared resid                 482.6402   Schwarz criterion  3.701900
Log likelihood                   -397.2744   F-statistic        52495.55
Durbin-Watson stat                1.631013   Prob(F-statistic)  0.000000
==================================================================
Inverted AR Roots                      .99
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Industrial Electric Customers

Dependent Variable: INDCUSDE

Method: Least Squares

Date: 01/14/14 Time: 13:42

Sample (adjusted): 1998M05 2013M11

Included observations: 187 after adjustments

Convergence achieved after 5 iterations

Variable	CoefficienStd. Error	t-Statistic	Prob.	
C	233.6868	57.54085	4.061232	0.0001
@MOVAV(NETDOV(-2)+NETWLM(-2),2)	0.047071	0.132402	0.355514	0.7226
SEP00	-28.00546	6.224159	-4.499477	0.0000
DEC99	-41.94899	4.397838	-9.538549	0.0000
MAY00	28.51461	4.397586	6.484151	0.0000
OCT00	-12.94260	5.505184	-2.350985	0.0198
FEB00	-28.70581	4.441264	-6.463432	0.0000
AUG00	27.93776	5.396929	5.176603	0.0000
OCT	-2.923323	1.173047	-2.492076	0.0136
AR(1)	0.975272	0.016240	60.05459	0.0000

R-squared	0.953882	Mean dependent var	270.8717

Adjusted R-squared	0.951537	S.D. dependent var	27.89679
S.E. of regression	6.141267	Akaike info criteri	6.519932
Sum squared resid	6675.583	Schwarz criterion	6.692719
Log likelihood	-599.6137	F-statistic	406.7782
Durbin-Watson stat	3.197282	Prob(F-statistic)	0.000000

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Inverted AR Roots .98

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Appendix F: DPL Zonal Load Model Equations

The following regressions were estimated using the EViews econometrics software package.

- Delmarva DE Gross Retail Output (MWh).

Dependent Variable: LGRODPLDE

Method: Least Squares

Date: 04/18/14 Time: 09:38

Sample (adjusted): 2002M02 2013M10

Included observations: 141 after adjustments

Convergence achieved after 13 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	77099.95	260008.5	0.296529	0.7673
ETDE*CDD65WLM	1.639143	0.100094	16.37609	0.0000
ETDE*HDD65WLM	0.308501	0.043783	7.046162	0.0000
@MOVAV(JPRIDE(-1)/(CPIU(-1)/CPI12)	-884059.6	284045.9	-3.112383	0.0023
@MOVAV(ETWLM(-2),1)	1927.904	752.0325	2.563591	0.0115
JAN	66975.59	14023.40	4.775987	0.0000
FEB	1961.054	10298.02	0.190430	0.8493
APR	-39807.63	7177.045	-5.546521	0.0000

JUL	24648.27	11363.23	2.169125	0.0319
AUG	42807.80	10611.82	4.033975	0.0001
NOV	-20502.44	9587.232	-2.138515	0.0344
DEC	40674.75	13270.89	3.064961	0.0027
OCT04	-30443.89	24659.15	-1.234588	0.2193
AR(1)	0.625777	0.072518	8.629321	0.0000

==

R-squared	0.925466	Mean dependent var	770809.4
Adjusted R-squared	0.917836	S.D. dependent var	98966.00
S.E. of regression	28367.79	Akaike info criteri	23.43791
Sum squared resid	1.02E+11	Schwarz criterion	23.73069
Log likelihood	-1638.372	Hannan-Quinn criter	23.55688
F-statistic	121.3014	Durbin-Watson stat	2.192742
Prob(F-statistic)	0.000000		

==

Inverted AR Roots .63

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- Delmarva DE Net System Output (MWh).

==

Dependent Variable: NSODPL

Method: Least Squares

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Date: 04/18/14 Time: 09:38

Sample (adjusted): 1999M12 2013M10

Included observations: 167 after adjustments

Convergence achieved after 9 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	552654.5	267042.6	2.069537	0.0402
(ETDE+ETSAL)*CDD65WLM	3.330024	0.131344	25.35353	0.0000
(ETDE+ETSAL)*HDD65WLM	1.115084	0.033261	33.52538	0.0000
@MOVAV(JPRIDPL(-3)/(CPIU(-3)/CPI12)	-914653.1	301491.4	-3.033762	0.0028
@MOVAV(ETDE(-7)+ETSAL(-7),8)	1580.494	591.4869	2.672070	0.0084
JAN	23175.92	10465.34	2.214540	0.0283
FEB	-108771.4	11764.79	-9.245501	0.0000
MAR	-53079.66	11299.23	-4.697635	0.0000
APR	-104664.3	9136.168	-11.45604	0.0000
JUN	46932.79	13929.90	3.369212	0.0010
JUL	121655.3	22000.28	5.529716	0.0000
AUG	128036.4	20565.23	6.225867	0.0000
SEP	60496.74	11217.77	5.392938	0.0000
NOV	-77280.39	7693.580	-10.04479	0.0000
FEB07	61398.09	28905.45	2.124101	0.0353

AR(1)	0.578166	0.067808	8.526516	0.0000

R-squared	0.978289	Mean dependent var	1575516.
Adjusted R-squared	0.976132	S.D. dependent var	205521.3
S.E. of regression	31751.58	Akaike info criteri	23.66018
Sum squared resid	1.52E+11	Schwarz criterion	23.95891
Log likelihood	-1959.625	Hannan-Quinn criter	23.78142
F-statistic	453.5937	Durbin-Watson stat	2.120464
Prob(F-statistic)	0.000000		

Inverted AR Roots	.58

- Delmarva Zonal Peak Demand (MW).

Dependent Variable: MWDPL

Method: Least Squares

Date: 04/18/14 Time: 09:38

Sample (adjusted): 1992M05 2013M10

Included observations: 258 after adjustments

Convergence achieved after 6 iterations

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Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-1781.453	193.8932	-9.187801	0.0000
(ETDE+ETSAL)*MWHDWIL	0.034379	0.002538	13.54331	0.0000
(ETDE+ETSAL)*MWCDWIL	0.061063	0.005092	11.99277	0.0000
@MOVAV(JPRIDPL(-3)/(CPIU(-3)/CPI12),	-1453.953	886.5137	-1.640079	0.1023
@MOVAV(ETDE(-2)+ETSAL(-2),6)	6.077629	0.560209	10.84886	0.0000
@MOVAV(((PDINCDE(-2)+PDINCSAL(-2))/(C18.18435CPI2.415015DE(7.529704L(-0.0000				
MAR	-139.0394	41.65676	-3.337739	0.0010
APR	-297.5616	43.36533	-6.861739	0.0000
JUN	513.7088	48.68677	10.55130	0.0000
JUL	611.8825	55.12265	11.10038	0.0000
AUG	624.8638	53.38461	11.70494	0.0000
SEP	372.4194	50.64503	7.353522	0.0000
OCT	-123.8987	50.26698	-2.464814	0.0144
NOV	-200.7217	43.68826	-4.594408	0.0000
AR(1)	0.177991	0.063521	2.802091	0.0055

R-squared	0.919262	Mean dependent var	2831.738
Adjusted R-squared	0.914611	S.D. dependent var	587.2589
S.E. of regression	171.6057	Akaike info criteri	13.18466

Sum squared resid	7155988.	Schwarz criterion	13.39122
Log likelihood	-1685.821	Hannan-Quinn criter	13.26772
F-statistic	197.6243	Durbin-Watson stat	1.982937
Prob(F-statistic)	0.000000		

===

Inverted AR Roots	.18

===

Appendix G: Delmarva Zone Peak Demand By Rate Class

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Delmarva Zone Summer Peak Demand By Rate Class

(Non-Coincident With PJM System Peak, July 18, 2013, 5:00 PM)

CUSTCLASSCODE	CUSTCLASSNAME (Description)	kWh at HE 07/18/13-17:00
DE_DEMECT	DE_DEMECTRANS	445184.233
DE_GSPTOU	Delaware General Service Primary Tou	378464.731
DE_GSPTOUH	Delaware General Service Primary Tou Hourly	7389.961
DE_GSPTOUMIN	Delaware General Service Primary Tou	4909.131
DE_GSSPHTG	Delaware General Service Space Heating	6479.092
DE_GSTTOU	Delaware General Service Transmission Tou	70754.326
DE_GSWTRHTG	Delaware General Service Water Heating	98.584
DE_LGSTOU	Delaware Large General Service	109296.393
DE_LGSTOUH	Delaware Large General Service Hourly	2835.671
DE_MGSOPS	Delaware Medium General Service Off Peak	3877.756
DE_MGSSBASIC	Delaware Medium General Service	263879.581
DE_ODECPRI	Delaware ODEC Primary	10751.782
DE_ODECT	DE_ODECTRANS	341154.318
DE_OLBASIC25	Delaware Outdoor Lighting Rate 25	0
DE_OLBASIC30	Delaware Outdoor Lighting Rate 30	0
DE_ORLBASIC	Delaware Outdoor Recreational Lighting	36.918
DE_RSBASIC	Delaware Residential Service	668353.134
DE_RSHEATING	Delaware Residential Heating	258001.352
DE_RSTOUND	Delaware Residential Tou Non Demand	439.391
DE_SGSBASIC	Delaware Small General Service	30957.226
MD_BERLINT	MD_Berlin Trans	3515.637
MD_GSP3TOU	Maryland General Service Primary Tou 3	98,141.20
MD_GSPTOU	Maryland General Service Primary	17,983.17
MD_LGS3TOU	Maryland Large General Service Tou 3	23,897.51
MD_LGSTOU	Maryland Large General Service	54,102.07
MD_ODECPRI	Maryland ODEC Primary	65,279.14
MD_ODECT	MD_ODECTRANS	185,734.23
MD_OLBASIC25	Maryland Outdoor Lighting Rate 25	-
MD_OLBASIC30	Maryland Outdoor Lighting Rate 30	-
MD_ORLBASIC	Maryland Outdoor Recreational Lighting	-
MD_RSBASIC	Maryland Residential Service	532,551.25
MD_RSTOUND	Maryland Residential Tou Non Demand	275.49
MD_SG2BASIC	Maryland Small General Service 2	148,695.86
MD_SG2OPS	Maryland Small General Service Off Peak 2	1,216.36
MD_SGSBASIC	Maryland Small General Service	45,921.48
MD_SGSCON	MD_SGSCONOWINGO	3,913.73
MD_SGSOPS	Maryland Small General Service Off Peak	32.83
MD_SGSSPHTG	Maryland Small General Service Space Htg	19,477.49
MD_SGSTN	Maryland TELECOM NETWORK	443.55
MD_SGSWH	MD_SGSWWTRHTG	32.33
VA_ODECT	VA_ODECTRANS	150,294.11

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Delmarva Zone Winter Peak Demand By Rate Class
(Non-Coincident With PJM System Peak, January 23, 2013, 8:00 AM)

CUSTCLASSCODE	CUSTCLASSNAME (Description)	kWh at HE 01/23/13-08:00
DE_DEMECT	DE_DEMECTRANS	296564.795
DE_GSPTOU	Delaware General Service Primary Tou	323809.315
DE_GSPTOUH	Delaware General Service Primary Tou Hourly	4929.905
DE_GSPTOUMIN	Delaware General Service Primary Tou	4626.645
DE_GSSPHTG	Delaware General Service Space Heating	5114.622
DE_GSTTOU	Delaware General Service Transmission Tou	111248.785
DE_GSWTRHTG	Delaware General Service Water Heating	193.144
DE_LGSTOU	Delaware Large General Service	101702.876
DE_LGSTOUH	Delaware Large General Service Hourly	745.986
DE_MGSOPS	Delaware Medium General Service Off Peak	2811.201
DE_MGSSBASIC	Delaware Medium General Service	185145.076
DE_ODECPRI	Delaware ODEC Primary	9683.626
DE_ODECT	DE_ODECTRANS	271614.325
DE_OLBASIC25	Delaware Outdoor Lighting Rate 25	869.644
DE_OLBASIC30	Delaware Outdoor Lighting Rate 30	2218.217
DE_ORLBASIC	Delaware Outdoor Recreational Lighting	11.692
DE_RSBASIC	Delaware Residential Service	302714.304
DE_RSHEATING	Delaware Residential Heating	374835.267
DE_RSTOUND	Delaware Residential Tou Non Demand	280.852
DE_SGSBASIC	Delaware Small General Service	26140.193
MD_BERLINT	MD_Berlin Trans	11791.473
MD_GSP3TOU	Maryland General Service Primary Tou 3	76455.943
MD_GSPTOU	Maryland General Service Primary	19299.653
MD_LGS3TOU	Maryland Large General Service Tou 3	14375.054
MD_LGSTOU	Maryland Large General Service	52662.396
MD_ODECPRI	Maryland ODEC Primary	59339.346
MD_ODECT	MD_ODECTRANS	164087.703
MD_OLBASIC25	Maryland Outdoor Lighting Rate 25	402.16
MD_OLBASIC30	Maryland Outdoor Lighting Rate 30	823.437
MD_ORLBASIC	Maryland Outdoor Recreational Lighting	25.117
MD_RSBASIC	Maryland Residential Service	601072.765
MD_RSTOUND	Maryland Residential Tou Non Demand	329.139
MD_SG2BASIC	Maryland Small General Service 2	105154.512
MD_SG2OPS	Maryland Small General Service Off Peak 2	705.085
MD_SGSBASIC	Maryland Small General Service	43913.75
MD_SGSCON	MD_SGSCONOWINGO	4019.787
MD_SGSOPS	Maryland Small General Service Off Peak	119.568
MD_SGSSPHTG	Maryland Small General Service Space Htg	18123.56
MD_SGSTN	Maryland TELECOM NETWORK	452.948
MD_SGSWH	MD_SGSWWTRHTG	15.83
VA_ODECT	VA_ODECTRANS	149790.311

Glossary: Data Dictionary

Zonal or Jurisdictional Energy and Demand Variables

LGRODPLDE – DPL's Gross Retail Output for the DPL Delaware jurisdiction. This is the amount of energy put into the system, before losses, to serve the needs of DPL's jurisdictional retail sales. Measured in MWh.

MWDPL – The monthly peak hour metered demand observed on the Delmarva Zone, non-coincident with the PJM peak demand measured in MW.

NSODPL – The monthly metered net send out for the Delmarva Zone. This data differs from the PJM Net Energy for Load in that the latter includes the losses on the 500 kV system that are allocated back to the zones by PJM. Measured in MWh.

Weather Related Variables

CDD65WLM – Monthly cooling degree days measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

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HDD65WLM – Monthly heating degree days measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

MWCDWIL – Cooling degrees at the time of the Delmarva Zonal peak demand (non-coincident with the PJM peak system demand) measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

MWHDWIL – Heating degrees at the time of the Delmarva Zonal peak demand (non-coincident with the PJM peak system demand) measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

Economic Variables

CPI11 – A factor, equal to 215.2239183, that is used to rebase CPIU so that it is expressed with a base year of 2008=100.

CPIU – The Consumer Price Index, All Urban, with a base period of 1982-84=100. The Consumer Price Index is published by the Bureau of Labor Statistics, US Department of Commerce.

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ETDE – Total Non-Agricultural Payroll Employment for the State of Delaware. Published by the Bureau of Labor Statistics, US Department of Commerce.

ETSAL – Total Non-Agricultural Payroll Employment for the Salisbury, MD Metropolitan Statistical Area. Published by the Bureau of Labor Statistics, US Department of Commerce.

PDINCDE – Total Personal Disposable Income for the State of Delaware. Published by the Bureau of Economic Analysis.

PDINCSAL – Total Personal Disposable Income for the Salisbury, MD Metropolitan Statistical Area. Published by the Bureau of Economic Analysis.

JPRIDE – The total all-in price of electricity, measured in $/kWh, for retail sales within the DPL DE jurisdiction, inclusive of all taxes, surcharges and the commodity component. The cost of electricity provided is estimated for choice customers by assuming that cost is equal to the cost experienced by DPL in serving Standard Offer Service customers within the DE jurisdiction.

JPRIDPL – The total all-in price of electricity, measured in $/kWh, for sales within the DPL service areas, inclusive of all taxes, surcharges and the commodity component. The cost of electricity provided is estimated for choice customers by assuming that cost is equal to the cost experienced by DPL in serving Standard Offer Service customers.

Dummy Variables

JAN – A categorical variable coded 1 during the month of January and zero otherwise.

FEB – A categorical variable coded 1 during the month of February and zero otherwise.

MAR – A categorical variable coded 1 during the month of March and zero otherwise.

APR – A categorical variable coded 1 during the month of April and zero otherwise.

MAY – A categorical variable coded 1 during the month of May and zero otherwise.

JUN – A categorical variable coded 1 during the month of June and zero otherwise.

JUL – A categorical variable coded 1 during the month of July and zero otherwise.

AUG – A categorical variable coded 1 during the month of August and zero otherwise.

SEP – A categorical variable coded 1 during the month of September and zero otherwise.

OCT – A categorical variable coded 1 during the month of October and zero otherwise.

NOV – A categorical variable coded 1 during the month of November and zero otherwise.

DEC – A categorical variable coded 1 during the month of December and zero otherwise.

FEB01 – A categorical variable coded 1 during the month of February 2001 and zero otherwise.

JUN00 – A categorical variable coded 1 during the month of June 2000 and zero otherwise.

MAR00 – A categorical variable coded 1 during the month of March 2000 and zero otherwise.

MAY00 – A categorical variable coded 1 during the month of May 2000 and zero otherwise.

AUG00 – A categorical variable coded 1 during the month of August 2000 and zero otherwise.

OCT00 – A categorical variable coded 1 during the month of October 2000 and zero otherwise.

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JUL00 – A categorical variable coded 1 during the month of July 2000 and zero otherwise.

APR00 – A categorical variable coded 1 during the month of July 2000 and zero otherwise.

SEP00 – A categorical variable coded 1 during the month of September 2000 and zero otherwise.

JAN00 – A categorical variable coded 1 during the month of January 2000 and zero otherwise.

OCT04 – A categorical variable coded 1 during the month of October 2004 and zero otherwise.

DEC99 – A categorical variable coded 1 during the month of December 1999 and zero otherwise.

FEB07 – A categorical variable coded 1 during the month of October 2004 and zero otherwise.

Appendix 5

Appendix 5 - CONFIDENTIAL MATERIAL OMITTED

Forecast of Retail SOS Supply Rates by Rate Class

2015-16	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
[redacted]											

Forecast of Retail SOS Supply Rates by Rate Class

2016-17	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
[redacted]											

Forecast of Retail SOS Supply Rates by Rate Class

2017-18	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
[redacted]											

Forecast of Retail SOS Supply Rates by Rate Class

2018-19	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer									$ 12.851053	$ 14.668955	$ 14.356445
Winter									$ 7.417059	$ 8.975509	$ 8.642780
Energy ($/MWH)											
Summer - all hrs	$ 0.088045		$ 0.086172	$ 0.088427	$ 0.087249	$ 0.086831	$ 0.050360	$ 0.071165	$ 0.042166		
DP&L On pk		$ 0.141359								$ 0.059169	$ 0.051638
DP&L Off pk		$ 0.051053								$ 0.042512	$ 0.039607
Winter - all hrs	$ 0.085949		$ 0.075862	$ 0.081215	$ 0.081317	$ 0.071936	$ 0.051052	$ 0.063461	$ 0.047901		
DP&L On pk		$ 0.131124								$ 0.060733	$ 0.051239
DP&L Off pk		$ 0.055158								$ 0.043603	$ 0.039289

Forecast of Retail SOS Supply Rates by Rate Class

2019-20	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer									$ 13.590868	$ 15.513840	$ 15.182076
Winter									$ 8.131647	$ 9.839753	$ 9.475397
Energy ($/MWH)											
Summer - all hrs	$ 0.097162		$ 0.095290	$ 0.097545	$ 0.096367	$ 0.095948	$ 0.050360	$ 0.080282	$ 0.044512		
DP&L On pk		$ 0.157882								$ 0.062343	$ 0.055010
DP&L Off pk		$ 0.056186								$ 0.044727	$ 0.042287
Winter - all hrs	$ 0.092133		$ 0.082046	$ 0.087399	$ 0.087501	$ 0.078119	$ 0.051052	$ 0.069645	$ 0.052380		
DP&L On pk		$ 0.142100								$ 0.066189	$ 0.056848
DP&L Off pk		$ 0.059224								$ 0.047411	$ 0.043747

Appendix 6

APPENDIX 6: PJM ISO MARKET OVERVIEW AND HISTORICAL PRICES

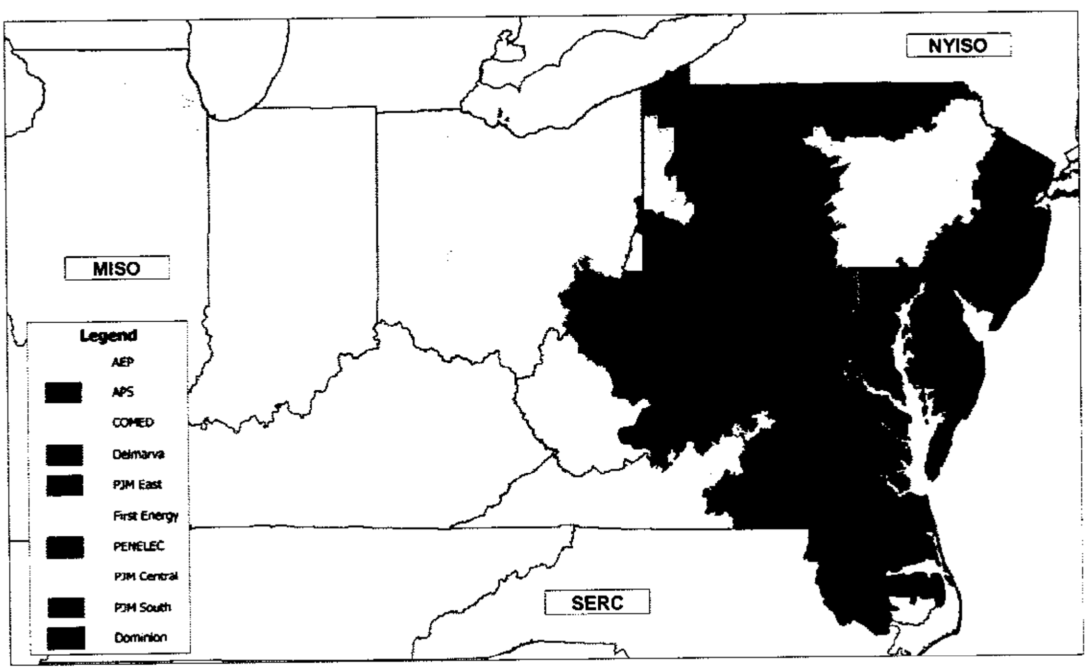
MARKET STRUCTURE

The electric power pool encompassing the Pennsylvania, New Jersey, and Maryland service territories was named the PJM Interconnect in 1956. PJM was designated a Regional Transmission Organization (RTO) by FERC in 2001. Since then, PJM's service territory has grown to include all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

The PJM Independent System Operator (PJM ISO) is tasked with administering the world's largest wholesale market and operating the world's largest centrally dispatched wholesale electric grid. The PJM ISO dispatches around 200,000 megawatts (mW) of generating capacity over more than 60,000 miles of transmission lines and ensures electric reliability to 60 million customers. The majority of PJM's territory is also part of the Reliability First Corporation (RFC), one of the regional organizations of the North American Electric Reliability Corporation (NERC). The Dominion service territory (eastern/central Virginia and northeast North Carolina) is part of the SERC Reliability Corporation.

Across PJM, there are several areas of significant and persistence price divergences, which represent zones in Pace Global's modeling approach. In our assessment, we have examined power pricing across ten distinct zones, with transfer capabilities modeled across each zone and with neighboring ISOs. Exhibit 1 shows the footprint of PJM, including the ten distinct zones simulated in Pace Global's market assessment.

Exhibit 1: PJM Footprint



Source: Pace Global.

The PJM ISO administers the wholesale electric market by providing the following primary functions:

- Performs continuous real-time operation of the bulk power system including generation dispatch and scheduling transmission flow;

- Maintains reliability in response to power system events;
- Provides coordinated transmission planning;
- Administers wholesale markets for trading electricity-related commodities.

The PJM ISO administers a multi-settlement system for buying and selling electricity-related products including energy, capacity, and ancillary services. As an independent entity, it facilitates the financial settlement of these products free of bias and continually monitors the market for anti-competitive behavior. The PJM energy market exchange consists of two settlements: one for the day-ahead market and another for the real-time market. The day-ahead market produces financially binding schedules for the supply and consumption of energy for the upcoming operating day. The real-time market is a spot market that accounts for deviations from the day-ahead market schedules.

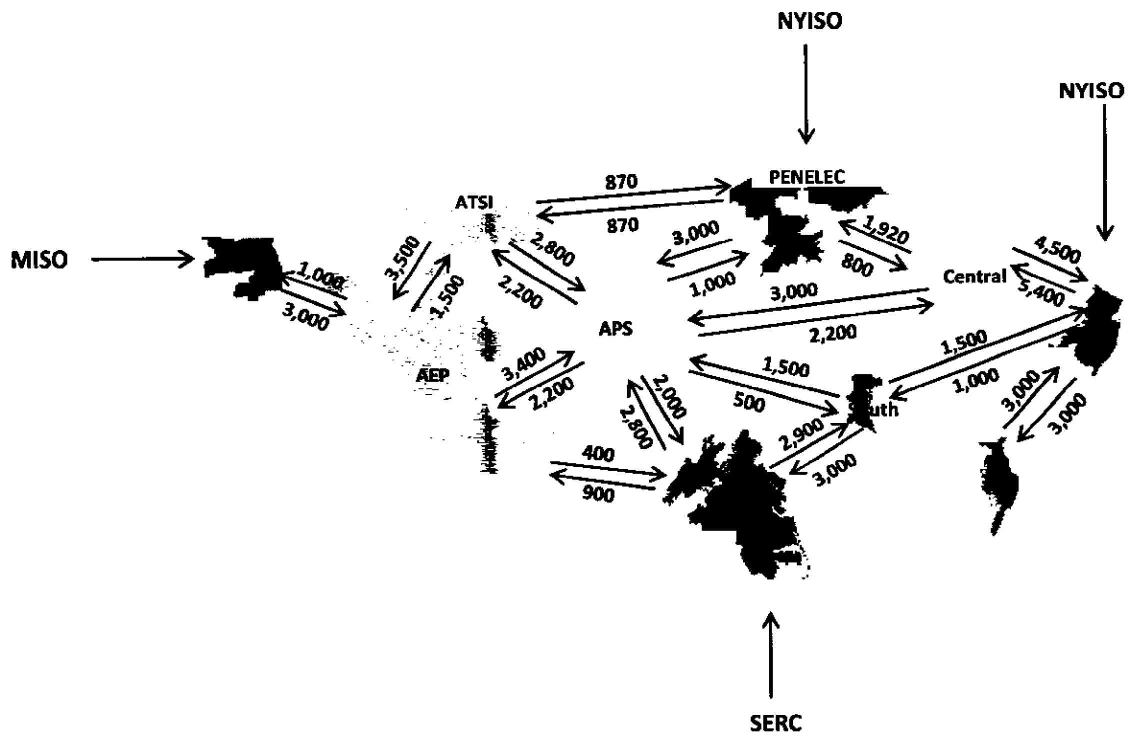
TRANSMISSION

Exhibit 2 displays the transmission capabilities (in mW) between the modeled PJM zones. Pace Global analyzes the PJM market area in accordance with transmission constraints across zones with significant and persistent congestion. In order to assess potential transmission upgrades, Pace Global assesses PJM's Regional Transmission Expansion Plan (RTEP) process, which is responsible for planning transmission system in the PJM territory. The latest load forecast outlook, published in January 2014 by PJM, projects lower summer and winter peak demand in all regions compared to the 2013 load forecast. This expectation, combined with slower economic recovery and increased energy conservation participation, contributed to less stringent transmission upgrades for the region in the near-term when compared to earlier assessments.

Within PJM, there are several major transmission projects aimed at bringing power from low-cost resources in the West and Central parts of the region to the load centers in the East. Notable expansion plans are described below:

- PJM is targeting transmission projects in Pennsylvania and New Jersey. PSEG and PPLS are collaborating on the 500kV Susquehanna to Roseland project, which was approved for construction in 2012 and is likely to be in service by 2015 or 2016. This project is included in our analysis.
- The Mt. Storm- Doubs 500 kV line is currently being upgraded by APS and Dominion and is likely to be in service by summer of 2015. This project is included in our analysis.

Exhibit 2: PJM Transfer Capability (MW)



Source: Pace Global.

PJM coordinates the continuous buying, selling and delivery of wholesale electricity through open, competitive markets. PJM balances the needs of suppliers, wholesale customers and other market participants. PJM oversees day-ahead and real-time energy markets as well as the Base Residual Auction for procurement of capacity and clearing of capacity prices.

RELIABILITY PRICING MODEL

The PJM Reliability Pricing Model (RPM) was implemented on June 1, 2007. It is designed to provide generators, demand response resources, and transmission owners with the economic incentives necessary to maintain system reliability and to ensure that sufficient generation capacity is available to meet the region's electricity demands. The RPM allows facilities to sell capacity for a 12-month period on a three-year forward basis through an auction process, creating a construct with greater cash flow stability than a bilateral capacity market.

The key characteristics of the RPM are:

- Three-year forward commitment of capacity delivery;
- Predetermined downward sloping Variable Resource Requirement (VRR) demand curve;
- Locational value of capacity;
- Integration with the energy markets of the PJM-ISO;
- Load Serving Entities (LSE) have the ability to opt out of the RPM at the discretion of the authorities of an applicable state, but must keep a higher reserve margin than participating LSE.

Load Deliverability Areas

The RPM establishes clear regulations as to what PJM-ISO zones will become load deliverability areas (LDAs). Pace Global's analysis assesses areas of significant transmission separation for capacity price projections.

VRR Curve

The VRR curve is the demand curve that determines the price at which given supply bids will clear. The VRR curve is tied to the Cost of New Entry (CONE) within the applicable LDA. The RPM-defined CONE (nominal $) was recently modified in FERC's January 31, 2013 ruling on PJM's CONE values. The Settlement CONE was then adjusted by the Handy Whitman Index. The CONE for the 2016-2017 delivery period was $380/MW-day ($139/kW-year) for the RTO, up 8.6 percent from the 2015-2016 auction. CONE area 1, which includes AE, DPL, JCPL, PECO, PS, and RECO, had the highest CONE at $415/MW-day ($152/kW-year), while CONE area 3, which includes AEP, APS, ComEd, Dayton, and Duquesne was set at $380/MW-day ($139/kW-year).

In order to integrate the RPM with the energy markets of the PJM, the energy and ancillary services (E&AS) gross margins for a hypothetical peaking unit are used to offset the CONE. The RTO's current calculated value for E&AS is $8.5/kW-year ($23/MW-day) (nominal $).

To calculate the VRR curve, the following equation is used:

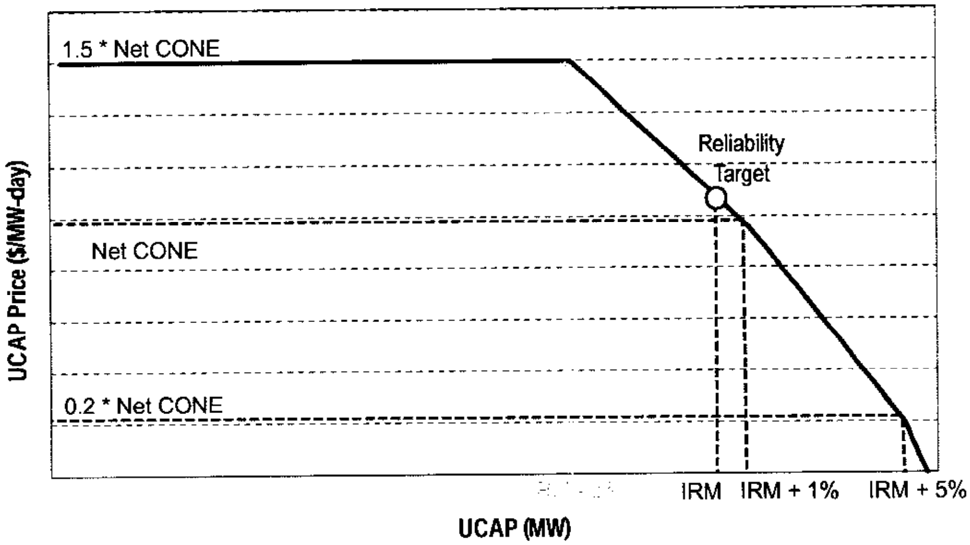
$$VRR = \frac{Multiple * (CONE - E\&AS)}{EFORd^{1}}$$

[1]where EFORd is the average system-wide equivalent forced outage rate of demand for the LDA

The multiple is the feature of the VRR curve that gives the curve its downward sloping shape. The RPM has a price cap through the use of a 1.5 multiple for all reserve margins below the Installed Reserve

Margin (IRM) minus 3 percent (for the 2016-2017 auction, this was 12.6 percent). The IRM, last specified as 15.6 percent, is the equilibrium point of the RPM with a multiple of 1. The multiple falls to 0.2 at the IRM plus 5 percent (20.3 percent). The PJM system-wide EFORd rate for the 2016-2017 auction was 5.70 percent. Exhibit 3 shows an illustration of the VRR curve.

Exhibit 3: VRR Curve Illustration



Source: Pace Global.

Auctions in the Reliability Pricing Model

A Base Residual Auction (BRA) is held three years and one month before the beginning of the delivery year. Three incremental auctions are held between the BRA and delivery year to allow market participants needed liquidity. Owners, or those with rights equivalent to owners, must enter offers into the RPM auctions specifying at what price they would supply capacity into the PJM. New generators may choose to fix their initial capacity payment for an additional two years beyond the initial delivery period, under certain circumstances.

The first and third incremental auctions are held in order to allow market participants to satisfy their commitment due to:

- Changes in the LSE peak load forecast,
- Cancellations or delays of a planned resource,
- Deratings, retirements, or forced outage rating increases of an existing resource,
- Transmission upgrades, or
- Variations in the value of a demand resource.

The second incremental auction is held only if the peak load forecast for the entire PJM-ISO changes by more than 100 MW. The PJM-ISO buys the necessary capacity on behalf of all LSE during the second auction. No VRR curves are used in this incremental auction, as transactions are completed solely through bilateral trades.

The RPM auction mechanism determines the cost of capacity on an annual basis. The algorithms used by the RPM auction are meant to lower the total cost to all LSEs, while clearing the most capacity. The VRR curve can, in some situations, act only as a price ceiling on the price of capacity at the applicable reserve margin. For example, if the last offer in an auction is below and inside the VRR curve, the point on the VRR curve vertically above the final offer is the final clearing price of capacity.

Capacity Price

Capacity prices in the BRA auction are first calculated by determining the marginal price of capacity for the entire PJM. An analysis is then performed for all LDAs to determine if the capacity that cleared initially plus the Capacity Emergency Transfer Limit (CETL) into the LDA fail to meet the reliability requirement of the LDA. The necessary locational price adder is then determined by performing an additional supply/demand balance using the supply curve (generator offers) and demand curve (VRR curve) of the region.

FERC's March 26, 2009, ruling on PJM's Reliability Pricing Model modified some rules regarding the inclusion of LDAs in the calculation of the capacity price. The ruling specifies that if any LDA had a locational price adder in any of the three preceding BRAs they would automatically receive a separate VRR curve. For the 2012-2013 auction, for example, PSEG North, EMAAC, SWMACC, and MAAC all automatically received separate demand curves. It also increased the stringency of the CETL requirements for LDA's making it more likely like that zonal divergences appear in BRAs.

LSEs and capacity resources do not pay and receive the same capacity prices in constrained LDAs. Capacity resources receive the clearing price of the LDA, while LSEs in the same LDA are charged the weighted average of the capacity in that LDA plus whatever imports into the LDA that were calculated in the auction process.

PJM also has Minimum Offer Price Rules (MOPR) for new generation resources. The old MOPR was adopted in 2011 in order to mitigate "buyer-side" market power by requiring all new, non-exempted resources to bid at a floor price (i.e. ninety percent (90%) of the Net Cost of New Entry) or higher, unless the resource can demonstrate, through a unit-specific review process, that a lower bid is justified based on the economics of that unit. Last December, PJM submitted revisions to its MOPR rule proposing to replace the unit-specific review process with two broad exemptions: one for "competitive entry" and one for self-supply LSEs. Under the PJM proposal, a resource would be subject to the MOPR unless it fit within one of the exemptions.

In May 2013, FERC partially approved PJM's filing on the MOPR. As per the Order, new resources would be subject to MOPR unless they fit into either the Competitive Entry exemption or the Self Supply exemption. However, FERC ordered that PJM should retain the unit-specific review so that resources ineligible for MOPR exemptions that have lower competitive costs than the default offer floor have a chance to demonstrate their competitive entry costs.

Generating Capability and the RPM

Resources in the RPM receive a capacity payment up to their net capability. This is defined as the net seasonal capacity of the unit, de-rated for its previous delivery year's 12-month average EFORd rating. For intermittent units, a three-year historical average capacity factor of the unit is used to derate the plant's capacity. Hydro units are not considered intermittent resources in the PJM.

Further revisions to the RPM have allowed for greater participation of demand side resources in the base auction and subsequent incremental auctions. Up until the 2016/2017 auction, PJM saw a consistent increase in the MW offerings of interruptible resources into the capacity market. The 2012-2013 auction ended the interruptible load for reliability product, but allowed the same resources to bid as demand response. As a result, offered MW for demand response increased from 1,652.4 mW (unforced capacity or UCAP) in the 2011-2012 auction to 9,847.6 mW (UCAP) in the 2012-2013 auction. Efficiency resources were allowed for the first time in the 2012-2013 auction; 652.7 mW of efficiency resources were offered into that auction, of which 568.9 MW (UCAP) cleared. The 2014-2015 BRA had an increase in cleared energy efficiency resources to 822 MW (UCAP). The 2014-2015 auction was the first in which two additional demand resource products were allowed (Annual DR and Extended Summer DR). The total amount of demand resources that cleared the 2015/2016 auction stands at 14,832 mW (UCAP), which represents a 55% increase from the 2013-3014 auction. Demand response and energy efficiency represented nearly 10% of the total capacity relied upon to meet load for the 2015/2016 delivery period. For the 2016/2017 auction, only 12,408 mW (UCAP) of demand resources cleared with another 1,117 mW from energy efficiency resources. The drop in cleared demand response was roughly 17% relative to the 2015/2016 auction with the drop in offered demand response even more pronounced at 27%.

Fixed Resource Requirement

The RPM allows LSEs to "opt-out" of the capacity market and address their capacity obligations through the Fixed Resource Requirement (FRR) method. The FRR capacity obligation method allows LSEs to self-supply capacity to meet any part of their load obligations. LSEs that choose the FRR method must demonstrate an ability to meet current and forecasted peak load obligations with owned or contracted capacity. The FRR period is, at minimum, five years, with a FRR plan due every year.

If the LSE has resources above and beyond its required amount, such resources can be sold at RPM auctions. However, the LSE cannot meet its capacity obligations through RPM auctions.

Proposed Capacity Performance Product

Recently PJM has proposed introducing a new capacity product called the "Capacity Performance" product. The product has been introduced to help address reliability issues similar to the weather-related performance issues that surfaced across the ISO during the 2014 polar vortex event. This product would provide stronger performance incentives and more operational availability and diversity during peak system conditions. The objective of the product is to provide PJM with more fuel security, enhanced operational performance, higher availability of generation resources, and flexible unit operations.

Eligible resources for the capacity performance product should be capable of sustained, predictable operation at an output equal to its quantity of committed installed capacity. Generators that burn only gas must also have a secured fuel supply with some combination of firm transport/firm commodity and access to storage. Alternatively, they must convert to dual fuel plant operations.

The new capacity performance product clearing prices would be expected to be significantly higher than the current annual capacity product, as generators are likely to tend to offer in the investment cost of adhering to the eligibility requirements of the capacity performance product. PJM's proposal requires 80% of the total capacity procured as capacity performance. Because the specifics of these proposed changes have not been finalized, the reference case and low gas case have been analyzed under current market structure rules.

2014-2015 Auction Results

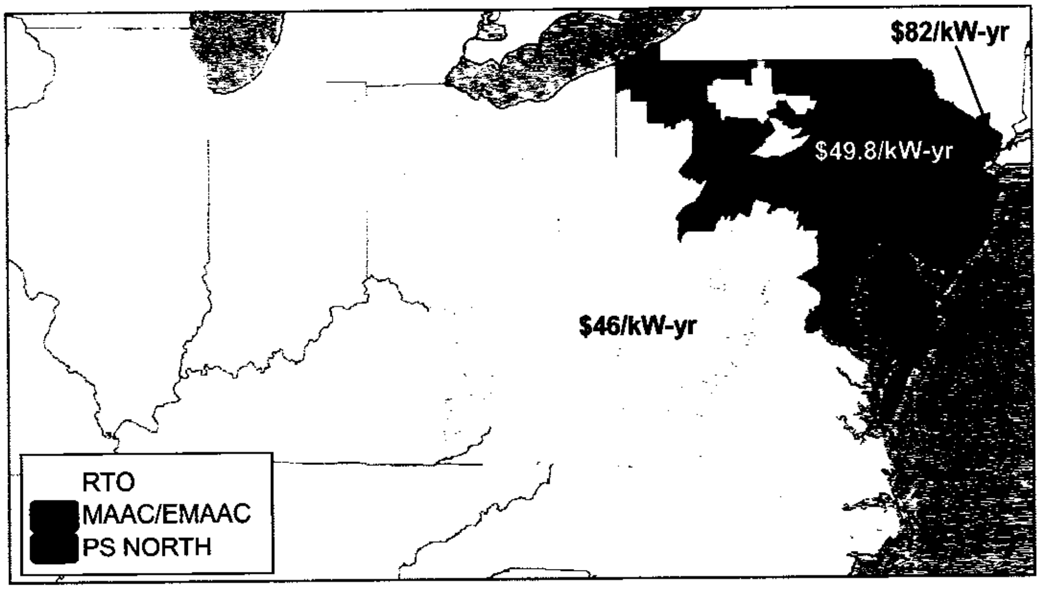
The results of the 2014-2015 auction, which were posted on May 13, 2011, are displayed in Exhibit 4. A total of 149,974 mW of unforced capacity cleared the auction representing a reserve margin over 19% at a RTO-wide clearing price of $45.9/kW-year ($125.99/mW-day). This price is over a 400 percent increase from the previous auction.

On April 12, 2011, FERC approved PJM's proposed revisions to its Minimum Offer Price Rule (MOPR), which was designed to prevent low and uneconomic power sale bids from entering the capacity market. FERC's ruling made the MOPR more likely to be used to prevent uneconomic entry, and changed the following key items: raised the conduct screen threshold benchmark price for combined cycle (CC) and combustion turbine (CT) generation plants from 80% to 90% of Net Asset Class Cost of New Entry (CONE); indexed CONE to the Handy-Whitman index; and no longer exempts resources from MOPR that are developed because of state regulatory or legislative mandate.

The proposal by PJM was partly a response to plans by Maryland and New Jersey to procure generation outside of the PJM wholesale market through state requests for proposals. PJM believed the actions of these states would have depressed regional capacity prices if its rules were not changed. The revised

MOPR is a positive outcome for natural gas-fired generators in the PJM capacity market, and it is expected to keep prices higher than originally anticipated in future auctions.

Exhibit 4: 2014-2015 Base Residual Auction Results (Nominal $/kW-yr)



Source: Pace Global and PJM.

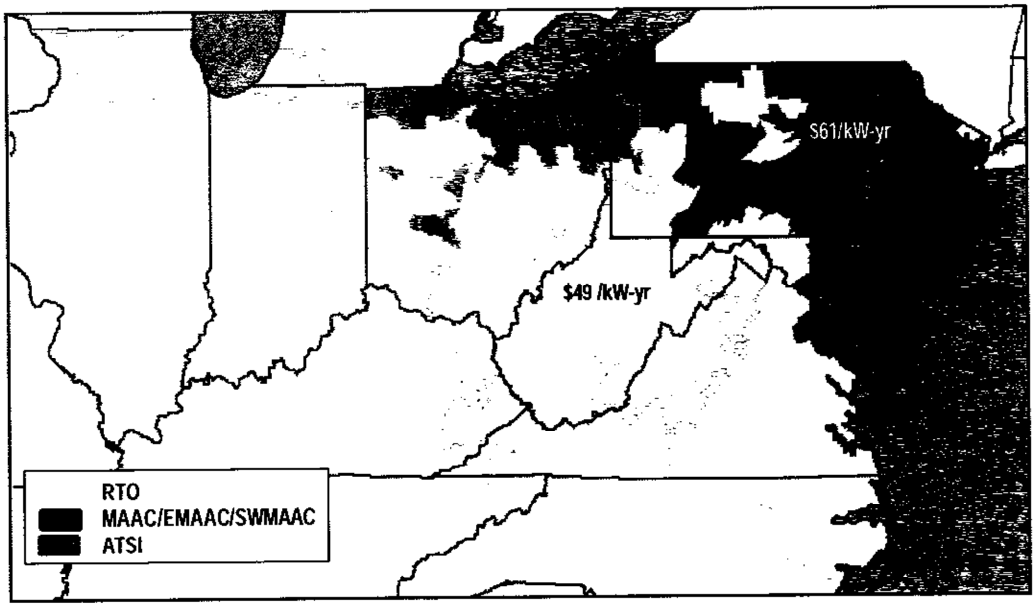
2015-2016 Auction Results

The results for the delivery year June 1, 2015 to May 31, 2016, saw the newly integrated ATSI region break out from the rest of the ISO. In response to significant planned coal capacity retirements in Ohio, the ATSI zone cleared at $125/kW-yr ($357/mW-day). The RTO cleared at $49.6/kW-yr ($136/mW-day), and the MAAC, EMAAC, and SWMAAC regions all cleared together at $61/kW-yr ($167/mW-day). Exhibit 5 below provides a map of the RPM clearing prices.

Record amounts of new generation, and demand and energy efficiency resources cleared the market during the auction. In total, 164,561.2 MW of capacity resources were procured, implying a reserve margin of 20.2% (0.6% higher than the previous year). A key driver of this auction's results was a record amount of planned capacity retirements (nearly 15 GW) that are expected to occur in the next three years. These retirements are driven by the expectation for environmental compliance regulations and costs. Despite a slightly higher RTO-wide reserve margin, transmission constraints and geographically concentrated retirements (especially in the ATSI region) led to clearing prices higher than those seen in the previous auction.

Nearly five GW (71 percent of offers) of new generation, 15 GW (74 percent) of demand response resources, and 900 MW (98 percent) of energy efficiency resources were procured. These were all record highs for the BRA. This auction also followed the recent trend of having an increase in the amount of gas-fired generation that cleared. All resource bids were subject to the MOPR.

Exhibit 5: 2015-2016 Base Residual Auction Results (Nominal $/kW-yr)

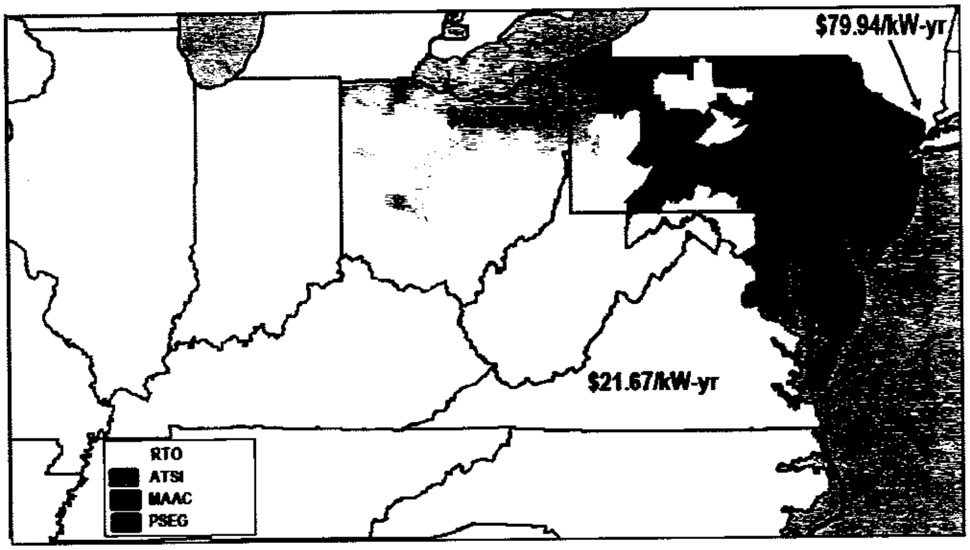


Source: Pace Global and PJM

2016-2017 Auction Results

The 2016/2017 auction for the delivery period June 1, 2016 to May 31, 2017 included the demand and capacity of the East Kentucky Power Cooperative, the newest member of PJM. This auction also utilized a 5% higher Net CONE relative to the 2015/2016 auction as well as a change in the Minimum Offer Price Rule (MOPR). New competitive generation capacity totaling 11 GW was granted MOPR exclusions by FERC for this auction. Roughly 5 MW of competitive and self-supply exempted capacity cleared the auction. As mentioned earlier, the results of this auction included prices that were lower than expected. Prices in the MAAC region cleared at $43.48/kW-yr ($119.13/mW-day), 29% lower than in the previous year. Prices in the ATSI region, which broke out for the first time in last year's auction, cleared at $41.69/kW-yr ($114.23/mW-day). This represents a 68% decrease from the previous year. Prices in the PS region cleared at $79.94/kW-yr ($219/mW-day), roughly 31% higher than in the previous auction. RTO prices cleared at $21.67/kW-yr ($59.37/mW-day), 56% lower than in the previous auction. The lower clearing prices are primarily a result of increased imports from MISO which increased by nearly 90% year-over-year. Other potential drivers include new generation capacity clearing with potential MOPR exclusions and anemic demand growth. The auction also appears to have been significantly influenced by bidding behavior of existing resources, resulting in cleared resources being price takers. Exhibit 6 provides a map with RPM clearing prices.

Exhibit 6: 2016-2017 Base Residual Auction Results (Nominal $/kW-yr)



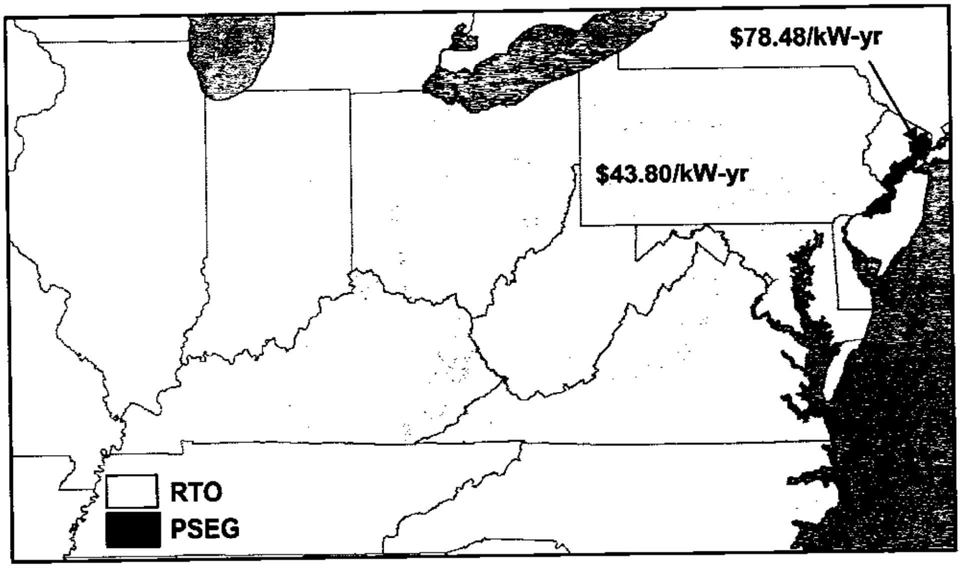
Source: Pace Global.

2017-2018 Auction Results

The 2017/2018 BRA for the delivery period June 1, 2017 through May 31, 2017 saw prices equilibrate across much of the ISO with the Public Service Electric and Gas Company (PSEG) region the only LDA breaking out with higher price separation from the rest of the RTO. Prices across the entire ISO, excluding PSEG, cleared at $43.80/kW-yr ($120/mW-day). This is slightly higher than the previous auction for the MAAC ($119.3/mW-day) and ATSI ($114.23/mW-day) regions, but more than double prices from the previous auction for the rest of the Unconstrained RTO ($59.37/mW-day). Meanwhile, prices in the PSEG LDA cleared about 2% lower than the previous auction with values at $78.48/kW-yr ($215/mW-day).

The primary change in value from the previous auction resulted in the Unconstrained RTO LDA where prices more than doubled year-to-year. Numerous factors contributed to this increase in capacity value. Starting with this auction, PJM introduced the concept of Capacity Import Limits (CIL) which placed a ceiling on the quantity of external resources that could be reliably committed to the PJM grid. This helped contribute to a decrease in external capacity imports of roughly 3 GW from the previous auction levels. In addition, roughly 1.5 GW less of Demand Response resources cleared this auction relative to the prior year. The net decrease in resources procured from external imports and DR led to the need for more than 6 GW of new capacity resources to clear the auction, a record amount in the annual BRA. Finally, lower net revenue expectations from generators from persistently low natural gas prices contributed to higher net CONE values across the system which pushed prices upwards.

Exhibit 7: 2017-2018 Base Residual Auction Results (Nominal $/kW-yr)



Source: Pace Global.

ANCILLARY SERVICES MARKET

Ancillary services support the reliable operation of the transmission system. Currently, PJM operates two ancillary service markets: Regulation service and Synchronized Reserve service.

- Regulation services supply the grid with electricity on short notice. Providers of synchronized reserves must have the capacity with the ability to ramp up quickly in response to an immediate need for additional power. Demand resources are also eligible to review synchronized reserve payments.

- Synchronized Reserve services account for minor short-term changes in power demand by helping match generation to load in real-time. LSEs can provide regulation by using their own generation to meet load, or by purchasing it from the market. PJM operates two Synchronized Reserve markets: The RFC Synchronized Reserve Zone is governed by the ReliabilityFirst Corporation, and the Southern Synchronized Reserve Zone is governed by SERC.

ENERGY MARKET

The PJM ISO operates a multi-settlement system for energy transactions under a locational marginal pricing system. The following section summarizes the mechanics of this system.

Day-Ahead Market

One day prior to actual dispatch, market participants submit supply offers and demand bids for the upcoming day. Using these offers and bids, the ISO constructs aggregated supply and demand curves for each node. By means of a least cost security constrained dispatch algorithm, the ISO determines the market clearing price – the intersection of the supply and demand curves. Offers that clear are the supply quantities below the clearing price and bids that clear are the demand quantities above the clearing price. The pre-cleared quantities imply flows across the transmission system to satisfy load at each node. The ISO performs a simultaneous feasibility test to identify transmission constraints that would inhibit these flows and re-dispatches the system to compute adjusted prices at source and sink nodes, known as

Locational Marginal Prices (LMP). LMP prices are intended to incent the siting of capacity near load centers and are calculated as follows:

$$LMP = System\ Marginal\ Price + Marginal\ Losses + Congestion$$

Cleared supply quantities are paid the LMP at the relevant source node. Cleared demand quantities pay the LMP at the relevant sink node (or an average price for all nodes in a demand zone).

The day-ahead market cleared quantities serve as schedules of supply and demand for the upcoming day. The schedules are financially and not physically binding. They function as forward contracts between suppliers and load serving entities. Scheduled supplies must produce the committed day-ahead quantities the following day in real-time or buy power in the real-time market to replace quantities not generated. Similarly, demand quantities have the right to consume the day-ahead quantity at the day-ahead clearing price. Demand that exceeds the day-ahead amount is purchased in the real-time market at real-time LMPs.

Real-Time Market

The real-time market is a spot market for electricity. The spot prices for energy are calculated at 5-minute intervals and reflect current system conditions, notably actual demand, generator availability, and transmission congestion. If these system conditions differ from the conditions assumed at the time of the day-ahead market, then generation schedules and demand consumption will differ from the schedules determined in the day-ahead market settlement. These deviations are established and priced in the real-time market settlement.

Generators with supply offers that did not clear in the day-ahead market may resubmit adjusted offers into the real-time energy market. During the real-time dispatch, the ISO is continuously monitoring system conditions and actual demand to anticipate projected needs, and if necessary, to commit any additional resources not already scheduled in the day-ahead settlement.

Based on anticipated conditions, the ISO produces expected real-time price signals and associated generation dispatch amounts. Generators are expected to meet these dispatch requirements – if they do not, actual realized prices will differ from the ex-ante price signals. Therefore, the generators will set real-time prices only if they adhere to the dispatch requirements.

Real-time market settlement produces LMPs for each pricing node based on actual system conditions and transmission congestion. All deviations from the day-ahead supply and demand schedules are settled at the real-time prices. Suppliers who do not produce their day-ahead commitments pay real-time prices for quantities not produced. Suppliers who produce more than their day-ahead schedules are compensated at real-time prices for quantities exceeding day-ahead commitments. Similarly, demand bidders are paid (or pay) the real-time prices for day-ahead quantities not consumed (or additional consumption) in real-time. In this fashion, the real-time settlement is a balancing market for energy.

FINANCIAL TRANSMISSION RIGHTS

The PJM-ISO uses a combination of Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) to distribute revenue related to transmission congestion and allow market participants to hedge risks associated with such congestion.

Financial Transmission Rights (FTR) are defined as "financial instruments...that entitle the holder to a stream of revenue (or charges) based on the hourly Day Ahead congestion price difference across the path." The purpose of FTRs is to allow market participants to hedge against the risk of congestion charges. The need for FTRs arose due to the ISO collecting greater revenues from load-serving entities than it paid to generators during periods of congestion. FTRs are available as an obligation or as an option. Options can have only positive values, while obligations can have negative values if congestion occurs in the opposite direction of the FTR.

Auction Revenue Rights (ARR) award the holder the right to receive an allotment of the revenues collected during PJM's annual and monthly FTR auctions. No auctions are used to allocate ARRs to market participants. ARRs are distributed to firm PJM transmission service and firm point-to-point transmission customers at no cost. ARRs designate a specific pathway and megawatt value that corresponds to certain FTRs that are to be sold during auctions.

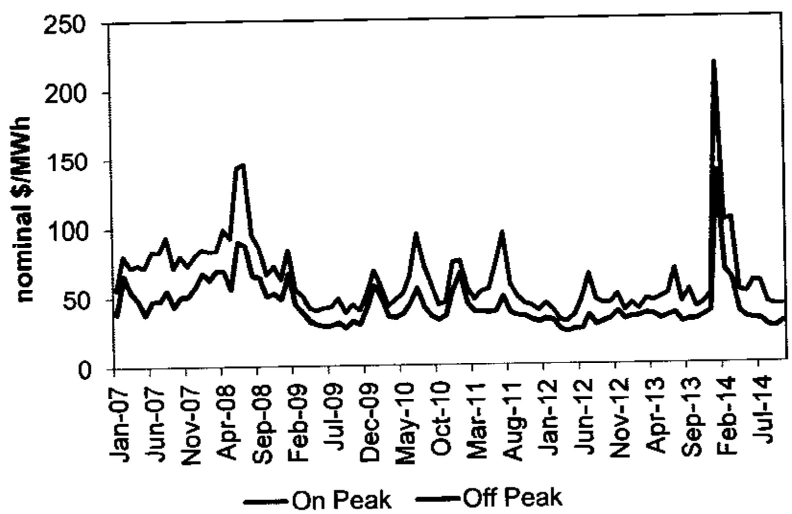
The ARR allocation is a multistage process. LSEs first apply for ARRs from specific resources along paths that serve their load. Later stages in the process allow the LSEs to then request any remaining ARRs throughout the system along paths that serve their load. At the end of each stage, a security constrained analysis of the requests for ARRs is performed in order to allow the PJM to remain revenue neutral. The analysis is designed to prevent the allocation of insufficient or excess ARRs during the allocation process.

Holders of ARRs can either convert them into FTRs for their own use or make them available in FTR auctions. ARRs are allocated to LSEs only on an annual basis, subject to reassignment due to load switching between LSE and are only available and convertible to market participants as an obligation. Therefore, holders of FTR obligations hold a liability when they are acquired from the PJM. If congestion is negative, or traveling in the reverse designation of the ARR, the holder of the FTR would be forced to compensate the PJM for the congestion.

HISTORICAL ENERGY PRICES

Exhibit 8 and Exhibit 9 provide a summary of historical monthly electricity prices for PJM_DPL zone. Prices in this region closely follow the price of natural gas, which is marginal for many hours of the year. This can be seen in sharp decline after commodity prices fell in 2008, with the price of natural gas bottoming out in the spring of 2012. Power prices in the first half of 2014 spiked due to the extremely cold winter, which caused plant outages, reduced working gas storage levels, and drove up natural gas prices in PJM. Other spikes tend to happen during the summer months when power demand is high and scarcity pricing is evident.

Exhibit 8: Monthly PJM DPL Energy Prices 2007-2014 (Nominal $)



Source: Pace Global and Energy Velocity.

Exhibit 9: Peak and Off Peak Monthly Energy Prices (Nominal $/MWh)

PJM DPL	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007	55.99	79.68	71.60	73.19	71.32	83.05	82.30	93.75	71.02	79.48	72.25	79.68
2008	84.58	82.70	83.21	98.62	92.89	143.12	145.86	95.56	85.47	66.07	71.82	62.48
2009	83.62	55.31	50.90	41.36	40.01	41.80	42.58	48.56	38.19	43.92	39.86	52.18
2010	68.09	56.91	42.92	47.55	51.77	64.59	95.19	71.42	58.29	43.61	45.36	73.43
2011	74.81	55.44	47.12	53.29	54.65	72.14	94.92	57.86	48.90	44.14	42.41	38.72
2012	43.88	38.83	31.36	30.81	35.06	47.44	64.22	46.26	43.85	43.99	50.10	38.21
2013	43.36	39.03	46.47	45.10	47.42	50.24	67.26	44.21	53.11	39.98	43.19	49.81
2014	216.28	101.73	103.38	52.59	50.47	58.57	57.83	43.07	41.05	41.16		

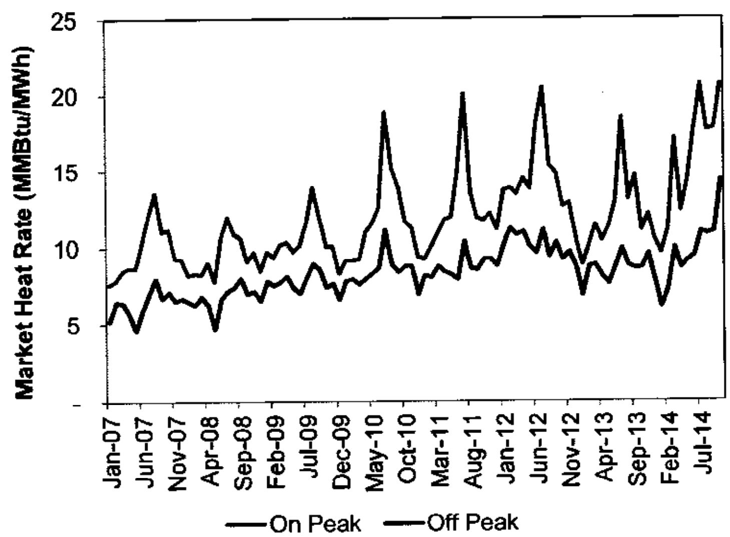
PJM DPL	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007	38.26	65.98	53.95	48.24	37.65	47.53	47.44	54.98	43.30	50.64	50.75	57.71
2008	67.06	62.46	69.05	68.57	55.77	89.95	87.33	65.02	64.21	50.75	52.77	48.38
2009	66.69	44.27	38.43	32.40	30.19	28.82	29.20	31.21	27.39	32.23	30.19	41.52
2010	57.79	49.03	35.29	34.33	37.06	44.41	55.88	41.54	35.12	32.60	35.34	54.13
2011	65.98	44.16	37.99	37.98	37.48	38.09	49.08	37.02	35.03	34.65	32.17	30.51
2012	32.54	31.37	25.04	23.30	25.51	25.05	34.88	28.30	30.38	31.95	37.44	31.73
2013	33.53	33.77	35.82	35.04	31.70	33.73	35.91	29.53	31.13	31.21	33.98	36.98
2014	137.85	66.55	60.14	36.66	32.15	31.25	30.65	26.36	25.31	28.62		

Source: Pace Global and Energy Velocity.

HISTORICAL MARKET HEAT RATES

Exhibit 10 shows the historic market heat rates for PJM DPL zone. The very low off-peak heat rates seen in 2008 and prior came as a result of high gas prices and coal influence on power prices from neighboring PJM regions, particularly during the off-peak period. Since the collapse in gas prices in 2009, the implied heat rates have steadily increased due to consistently low natural gas prices. However, in Eastern PJM and the DPL zone, summer scarcity has been high, with summer heat rates around 20 MMBtu/mWh. High electricity demand during the winter cold snap in early 2014 resulted in high market heat rates normally seen during the summer months.

Exhibit: 10 Historical PJM DPL Market Heat Rates (2007-2014)



Source: Pace Global and Energy Velocity.

Appendix 7

APPENDIX 7: FUEL MARKET ASSESSMENT

PRICE RELATIONSHIPS AMONG FUEL MARKETS

The petroleum, natural gas, and coal markets each have their own distinct pricing dynamics. However, fuel interchangeability in some end-use applications and oil-based natural gas pricing conventions in Europe and Asia create value linkages that can often overshadow other value considerations, creating a degree of price correlation. An example is the New England heating market, where fuel oil and natural gas compete for market share. Although short-term fuel switching capability is limited to the largest residential and commercial heating systems, the price of heating oil provides a soft cap on natural gas prices in the region. While gas prices usually move independently of heating oil prices, when demand is high and supplies are tight the two commodities trade in close correlation to spot markets. Similarly, while coal-gas-oil interchangeability is limited to a relatively small number of large boilers, an increase in oil and gas prices allow coal producers to raise prices without fear of market share loss, creating another weak but evident link. Conversely, a fast drop in natural gas prices to low levels, such as those that prevailed in most of 2009, in the summer of 2010, and most recently in early 2012 can induce some fuel switching and put downward pressure on coal prices. In general, the price correlation of oil and gas markets has been closer than that of gas and coal markets in the U.S., but deviations from any established pricing relationship between the fuels can be prolonged and significant if the supply/demand balances in any two commodities are out of step.

Generally speaking, the crude oil market is truly a global market, with prices adjusted consistently for location value and product quality. Price deviations only arise due to a mismatch between the availability of a particular grade of crude and market demand or compatible refinery capacity. Oil is easily and cheaply transported by pipe, rail, truck or ship and is easy to store in above-ground tanks. Natural gas, by contrast, is relatively difficult and expensive to transport and store, requiring high-pressure pipelines and underground reservoirs to contain and control the gaseous fuel. Therefore, natural gas markets have historically been geographically demarcated by integrated production, transmission, storage and distribution systems that are self-contained and largely isolated from other such systems.

In Europe and Asia, the natural gas industry was created and managed primarily by central governments, large state-sanctioned monopolies and a handful of dominant suppliers of both pipeline gas and ocean-borne liquefied natural gas (LNG), a super-cooled fluid with 600 times the energy density of vapor-phase natural gas. In such concentrated and controlled markets, crude oil and oil product prices have been used as a fair-value metric for pricing both domestic gas supplies and imported volumes. By contrast, the North American gas industry emerged from the independent efforts of thousands of privately-owned producers, pipelines, local distributors and major consumers, and has been predominantly self-sufficient through its evolution over the past 200 years. Therefore, in the 20+ years since wellhead price decontrol came to the U.S. and Canada, the North American gas market has been a generally self-contained and independent commodity market, with prices governed by local supply and demand balances on a daily basis. Regional markets are well integrated by an extensive system of pipeline infrastructure and the high level of transparent transactional activity that provides a reliable price discovery mechanism. As a result, the statistical correlation of price changes in gas and oil markets has been loose over the last decade and correlation between the two commodities is currently very low.

For this correlation to tighten in the coming years, domestic gas demand must outstrip supply, and LNG, with global prices indexed to oil markets, would have to become the marginal supplier of gas to the market. If U.S. consumers were forced to compete on price for marginal LNG cargoes that often price against an oil index, the oil/gas correlation would likely strengthen significantly. However, North America is unlikely to remain an off-season dumping ground for surplus LNG on world markets, and domestic supply largely from unconventional sources is expected to prevail over growth in gas demand. Accordingly, any increase in the statistical correlation of North American gas prices and world oil prices is likely to be modest.

If and when the U.S. starts competing for LNG cargoes during periods of high demand (major LNG markets are all located in the Northern Hemisphere and experience synchronous peaks in demand), there would be a growing gravitational pull on the U.S. gas market to align itself with world LNG market pricing. In light of the many independent market developments needed to produce this effect, the timing and sequencing of its occurrence is impossible to predict with any accuracy, but increasing North American statistical price correlation between oil and gas could be evident as early as 2013 or might be deferred for a decade or more, if ever, if domestic gas resources are aggressively developed.

As the global oil market is least affected by the price of other fuels, Pace Global's market driver summary for the petroleum market is presented first.

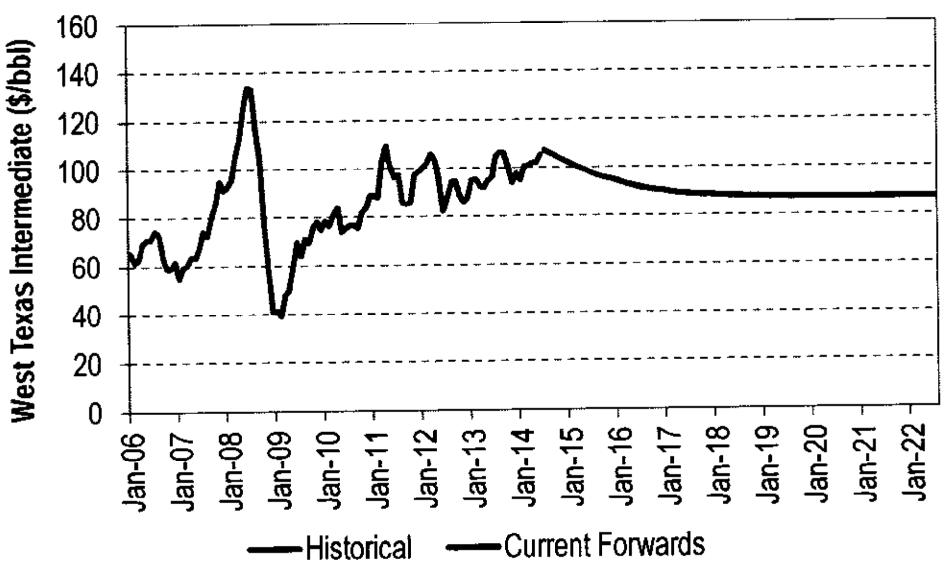
PETROLEUM

WTI Crude Oil Prices

After hovering between $20 and $40/bbl for two decades, crude oil prices have shown significant increases in volatility during the past five years. Between summer 2008 and summer 2009, the market value of a barrel of West Texas Intermediate ("WTI") crude oil varied by roughly $110, with the crude price touching $147/bbl in July 2008 before dropping to below $40/bbl in January and February of 2009 and then rebounding back to the $70-80/bbl level where they remained through the end of 2010. Market fundamentals were a significant part of the large price swings, but clearly the financial and economic downturn – first in the U.S. but quickly spreading around the world – played a substantial role. In 2011, despite a 4 percent increase in domestic production, prices rose to an annual average of $95/bbl as unstable political conditions in oil-producing regions of the Middle East and North Africa (MENA) threatened the global supply.

This combination of circumstances – rapidly increasing North American crude production and rolling crises in the MENA region – have continued to tug at domestic and global crude prices in the years hence. Spot prices in 2013 averaged just under $100/bbl. Year-to-date spot prices were just over $100/bbl in the summer, with recent declines into the $80/bbl range. Exhibit 1 shows historical WTI prices with the forwards.

Exhibit 1: Historical and Forward WTI Prices (Nominal$/Bbl)



Source: Pace Global, EIA for historical spot prices, and CME Group for current forward price strip.

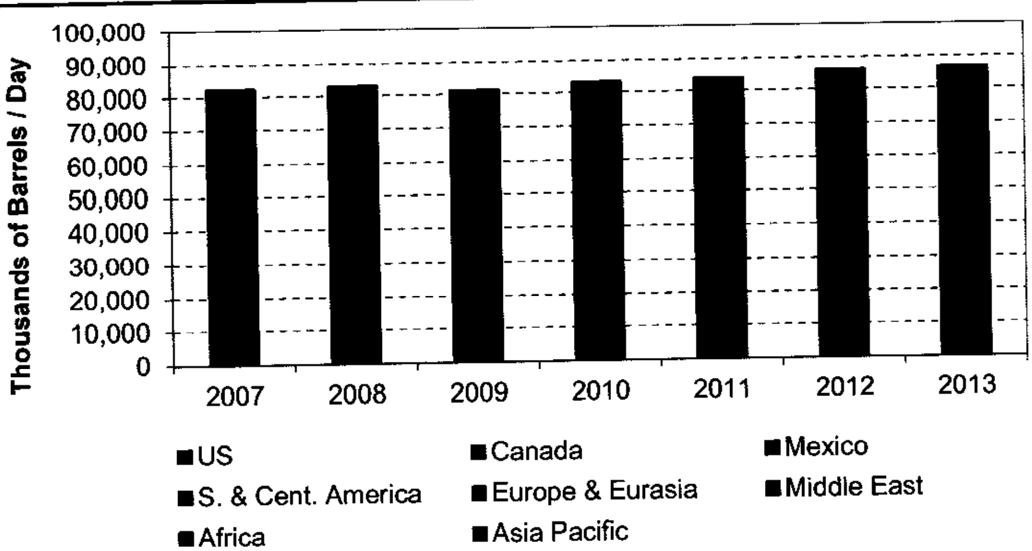
Oil Demand

As noted above, the U.S. economy preceded the rest of the world into economic recession during 2008, dragging oil consumption down 6 percent from 2007 levels. The OECD as a whole saw oil demand fall 3.6 percent, while global demand fell by less than one percent, given damped but positive growth in Chinese demand and continued demand growth in other non-OECD countries, particularly the Middle East. Domestic consumption increased 2 percent year-over-year in 2010, in line with modest economic recovery, but since the trend has been generally downward. Consumption fell by 1.3 percent and another 1.8 percent in 2011 and 2012, respectively, before recovering 2.1% in 2013, in as prices as prices hovered between $90-110/bbl.

Oil Supply

Global oil production by region, which has remained fairly consistent over the last several years, is provided in Exhibit 2. The recent EIA update on non-OPEC oil production shows that the steadily climbing oil price from 2003 into 2008 has borne fruit in terms of new production in 2009 and 2010, but these gains were largely offset by major declines in Mexico's giant Cantarell Field and aging North Sea properties. OPEC crude oil production was 33.1 million bbl/d in 2009, down 2.5 million bbl/d from year-earlier levels, in recognition of record-high inventory levels in the U.S. and elsewhere. It fell an additional 10 percent in 2010 to land at 29.8 million bbl/d; 2011 consumption increased by only 0.2 percent. OPEC production rebounded to 30.9 million bbl/d in 2012, representing a 3.6 percent year-over-year increase. Meanwhile, global crude oil production grew by 2.6 percent year-over-year in 2012 to over 86 million bbl/d and grew a modest 0.7 percent in 2013 to reach over 86.8 million bbl/d. The U.S. continues to lead the world in crude production growth, which increased by nearly 50% (2.4 MMbbl/d) between 2008 and 2013. Pace Global scenario analyses on future oil supplies range from a benign forecast of stable to weakly declining demand as the OECD focuses on import reductions and China constrains transportation fuel demand growth to a more troubling outlook in which sharp curtailments in available OPEC supplies due to due to widening sectarian warfare leads to bidding wars for available supplies.

Exhibit 2: Oil Production by Region (Thousand Bbl/d)



Source: BP Statistical Review of World Energy 2013, Pace Global.

NATURAL GAS

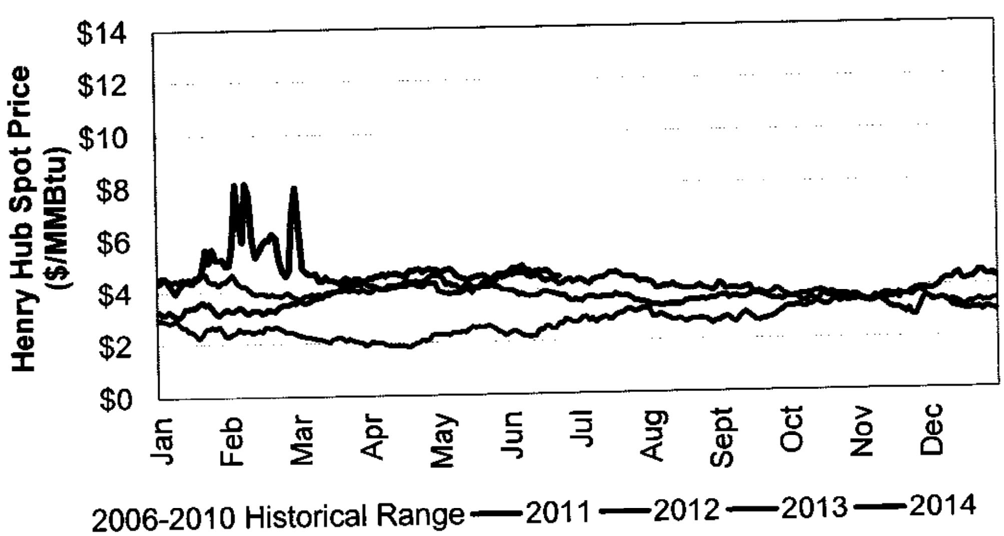
The principal location for natural gas trading in the U.S. is the Henry Hub in Louisiana. Due to the volume of physical trading at this location, Henry Hub has also become the location for financial market trading on the NYMEX. Regional gas prices are based on basis differentials from the Henry Hub to other delivery locations. Regional basis rises (widens) when local production declines and the cost of transporting gas between regions increases and when rising demand causes high utilization of regional pipeline and storage infrastructure. Conversely, increases in local production, and the available pipeline and storage capacity relative to demand cause basis differentials to decline (narrow).

Henry Hub Price

U.S. natural gas production has been increasing steadily over the last five years, which can be attributed to unconventional shale plays that now account for approximately 40 percent or more of the country's gas supply in 2013, up from 1 percent in 2000. During this time period, unconventional gas production has changed the perception of gas markets and has been the primary driver of Henry Hub pricing since prices dropped from winter 2008 highs. According to Baker Hughes, the U.S. gas rig count dropped from 8,219 rigs in August 2008 to a low of 1,061 rigs in March 2014 and all the while production continued at near record highs (see Exhibit 7).

Since the end of 2010, prices at the Henry Hub have been at or below the previous five-year low. Exhibit 3 shows the range of prices from 2006 to 2010 as well as where prices have been over the last three to four years, highlighting the major changes that have occurred in the natural gas markets largely as a result of shale development. An unseasonably cold and long winter in 2014 caused Henry Hub prices to return to the historical range, with periods reaching the upper end of that range. Prices through 2014 have managed to remain above levels witnessed in the previous three years as producers try to replace the depleted gas storage levels.

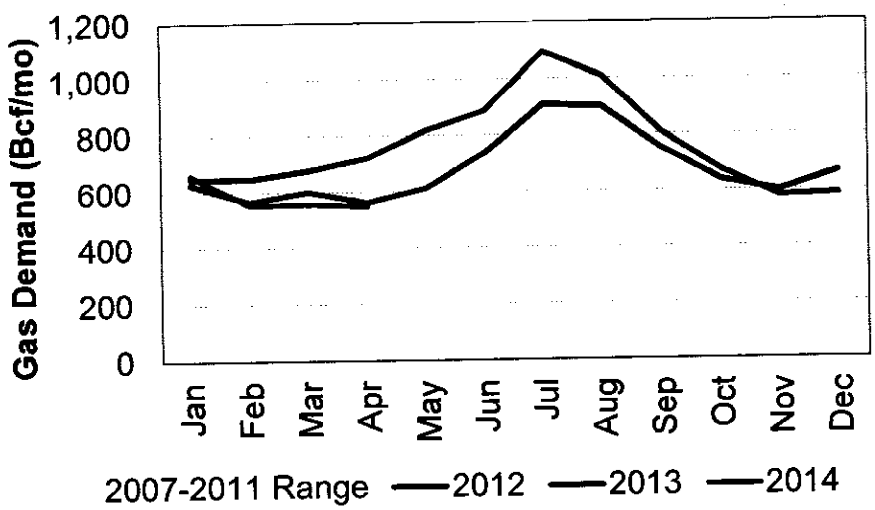
Exhibit 1: Historical Henry Hub Price Range (Nominal$/MMBtu)



Source: Pace Global, Platts, and SNL Financial.

Exhibit 4 shows the monthly range of power sector gas demand in the U.S from 2007-2011, as well as the demand for the last three years. Power sector gas demand has matched very closely to levels witnessed in 2013 and significantly lower than 2012 on account of higher prices. This trend is expected to persist through the rest of the year.

Exhibit 4: **Historical Power Sector Gas Demand (Bcf/mo)**

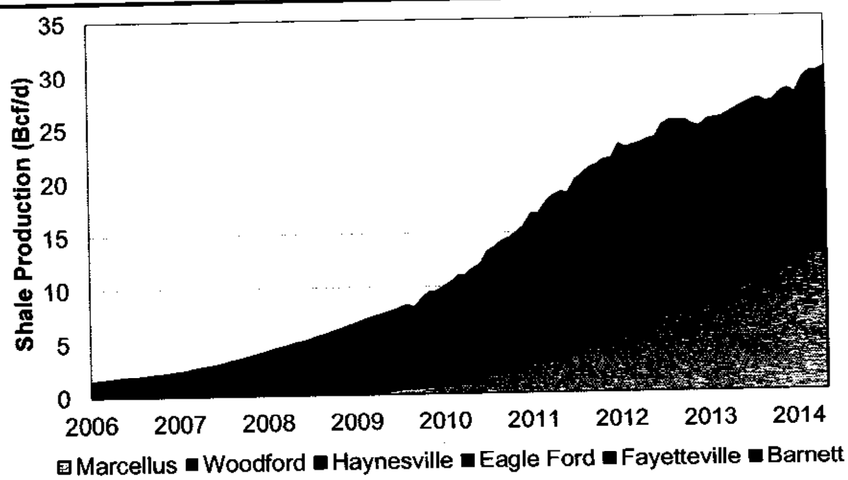


Source: Pace Global, EIA.

Historically, the range of monthly power sector gas demand has been fairly narrow. With prices at record lows in 2012, however, gas-fired power generation became more economical, resulting in coal-to-gas switching in many regions. Power sector gas demand in the four quarters of 2012 was up 26 percent, 29 percent, 14 percent, and 6 percent respectively, compared to the same periods in the previous year. Despite the increased demand, there was no significant price response, partly due to a market oversupply spurred by a warm winter and continued strong shale production. Gas prices rebounded in 2013, reducing the year over year gas consumption for power generation. However, annual gas consumption for power generation in 2013 was above the historical range.

The six major shale plays in North America have seen a 400 percent increase in production since 2008 (see Exhibit 5). The Marcellus shale play, located in western Pennsylvania, western New York and eastern Ohio, has changed the natural gas pricing dynamics in the Northeast, a region that has historically experienced very high gas prices in the winter due to high demand and transportation constraints. As drilling slows due to the general oversupply as well as waning investment in dry-gas shale play development, Pace Global expects the market to begin to stabilize, placing upward pressure on prices at the Henry Hub over the next three to four years.

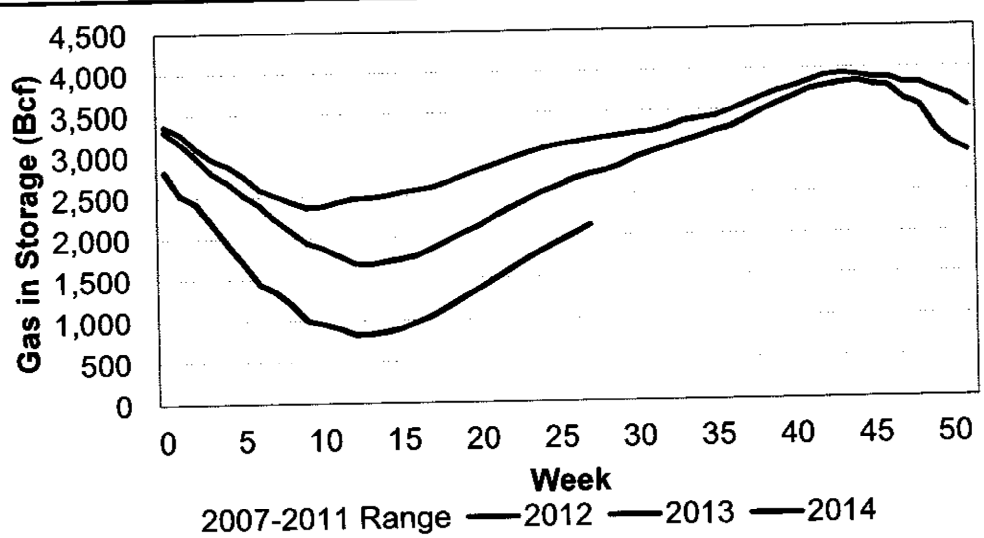
Exhibit 5: Historical Gas Production by Shale Play (Bcf/d)



Source: Pace Global, EIA

In 2011, despite power sector demand that had recovered from recessionary lows and some leveling out of gas production, there were still large volumes of natural gas injected into working storage. This resulted in an average annual Henry Hub price of $4.01/MMBtu. In 2012 gas storage levels were well above the previous five year range, reaching as high as 61 percent above the 2007-2011 range in April 2012 (see Exhibit 38). As of March 2013, however, total US underground working storage stood at 1,876 Bcf, still higher than the 2007-2011 range but much lower than during the same time in 2012. The cold snap in early 2014 and sustained low temperatures drove the available gas in storage to the low level of 822 Bcf. Storage levels have rebounded since, but levels remain below the five year average witnessed between 2007 and 2011.

Exhibit 6: U.S. Natural Gas Working Storage

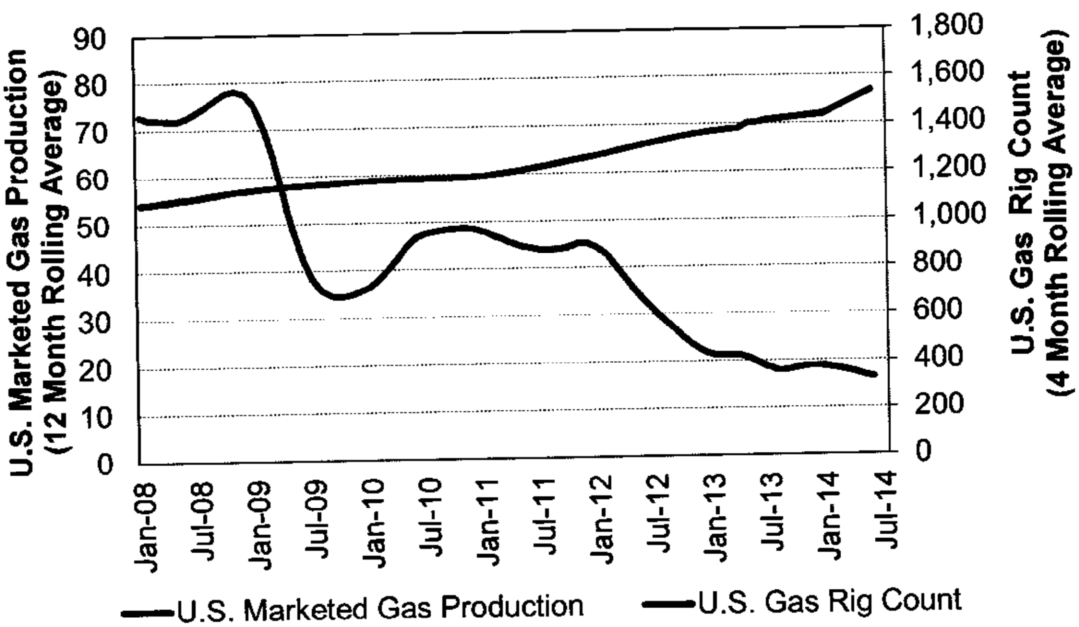


Source: Pace Global

Henry Hub cash price levels languished at the start of 2011, struggling to eclipse $5.00 per MMBtu even in the premium winter months and continued to lag throughout 2012. Spot prices during the first half of

2012 averaged only $2.36/MMBtu, the lowest price for that time period since 1999, and only slowly began to recover during the second half of 2012 to $3.14/MMBtu. 2013 saw Henry Hub cash prices increase to $3.73. As a result, U.S. natural gas producers slowly began adjusting their business models to find better investments than dry natural gas drilling and production. Despite the fact that the overall number of gas rigs drilling in the U.S. has rebounded from recessionary lows, as seen in Exhibit 7 below, the proportion of rigs drilling for gas is falling substantially and many of those rigs have been deployed to drill for crude oil. In fact, the number of US rigs currently drilling for oil has eclipsed those drilling for natural gas, the first time that this occurred since the mid-1990s. This strong trend can be seen in Exhibit 8. In the longer-term, reduced CAPEX in gas drilling may have the effect of rationalizing some production and helping to balance the currently oversupplied gas market.

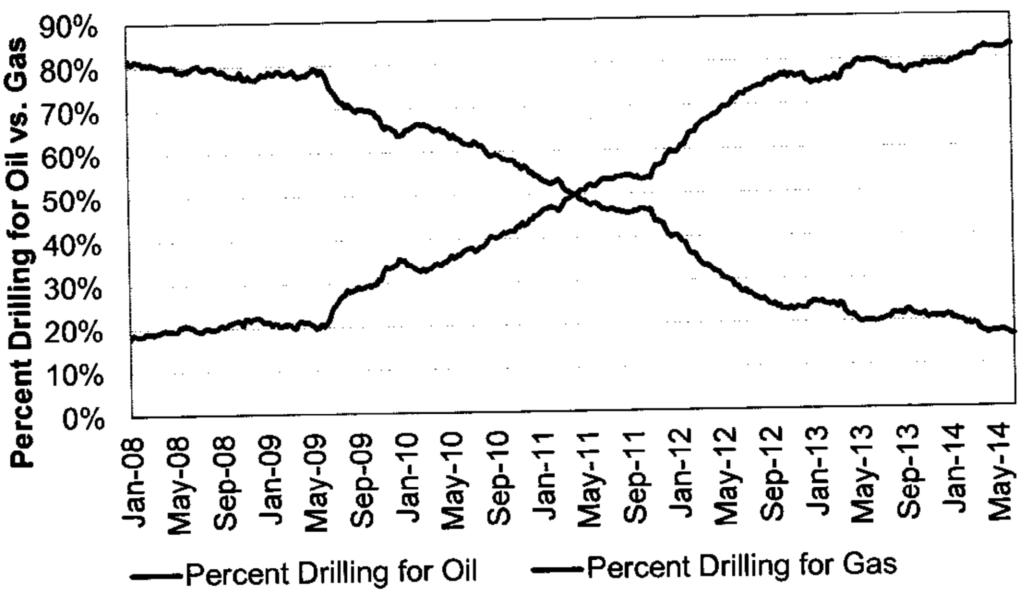
Exhibit 7: U.S. Natural Gas Production and Drilling Rig Count



Sources: Rig count – Baker Hughes; production – EIA. Updated through June 20, 2014.

In the market, rigs can be seen being removed from dry gas plays where development of core areas is largely complete, such as the Barnett Shale, and being redeployed in oil plays such as the Bakken Shale in North Dakota and in the liquids-rich natural gas plays such as the Eagle Ford Shale in south Texas. Part of this trend can also be attributed to rigs that are now freed up as they are no longer under hold-by-producing lease terms. Hold-by-producing lease terms required natural gas producers to drill wells in order to secure their long-term leases on land, and this was one reason that they continued to drill new wells even with Henry Hub prices languishing, supporting the oversupply situation in the markets. However, Pace Global has seen the first signs that this trend is beginning to change as hold-by-producing lease terms are slowly expiring in places such as the Haynesville Shale. Rigs that were drilling under these lease terms are now free to move to oil and natural-gas-liquids-rich plays and Pace Global has observed rigs from the Haynesville Shale being redeployed several hundred miles south in the Eagle Ford Shale. The effect of this shift in rigs to oil and liquids-rich plays in that less dry, pipeline quality natural gas will be produced per rig, as dry gas is in lower concentrations in these plays. Thus, the shift will slowly ameliorate the oversupply in the market.

Exhibit 8: Percentage of U.S. Rigs Drilling For Oil vs. Rigs Drilling for Gas



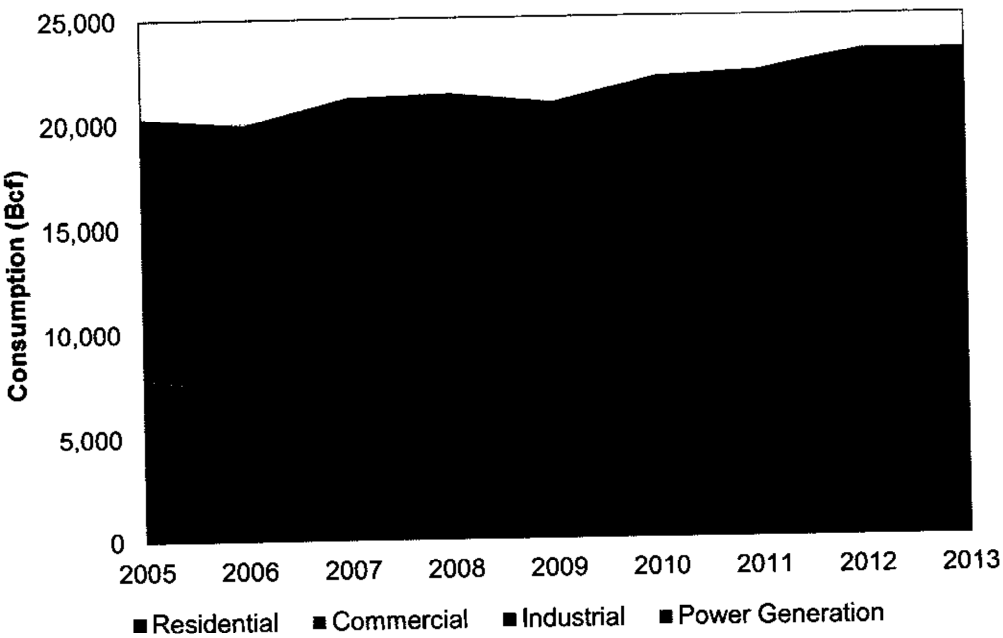
Source: Baker Hughes. Updated through June 20, 2014.

According to the EIA, 2010 total U.S. gas consumption rose 5.1 percent over 2009, largely driven by gas use in the electricity generating sector, which was up 7.5 percent, and industrial demand which had a year-over-year gain of 10.7 percent in 2010. 2011 consumption rose 1.2 percent over the previous year, in large part driven by more power sector demand. With low prices resulting in coal-to-gas switching, year-over-year consumption growth in 2012 was significantly higher at 4.4 percent over 2011. Power sector demand for gas in 2012 rose 20.6 percent over 2011. The rebound in gas prices seen in 2013 significantly degraded the gas generation advantage resulting in a decline of gas consumption for power generation of 11 percent. Preliminary data from early 2014 suggested power sector gas consumption in 2014 will be very similar to levels experience the previous year.

Generally, a trend of increased gas usage in the power sector at the expense of coal burn has emerged since the summer of 2009. With natural gas prices still relatively cheap as compared to recent years, and coal prices rebounding (see below for a discussion of the coal markets), there has been some switching to gas-fired units from coal-fired units in the dispatch order in certain NERC regions, particularly in shoulder-season months. Utilities in regions where gas transportation costs are relatively low and coal transportation costs are high, i.e. the SERC region, have announced the shutdown of certain coal units in favor of increasing utilization at intermediate gas units. Pace Global has captured this increased demand for natural gas in its hourly modeling of plant dispatch in the regions studied in this report.

Exhibit 9 shows total historical gas demand by sector. Outside of power generation, natural gas demand has been weak for quite some time. On the industrial front, gas usage has been slipping since the early 2000s, when demand was running well above 20 Bcf/d. Industrial gas consumption in the recent recessionary period in the U.S. dropped precipitously, hitting a low of 16.9 Bcf/d in 2009. The situation has since improved – industrial gas usage in the U.S. in 2014 averaged 20.4 Bcf/d, the highest consumption rate since 2004. This recovery remains tenuous, however, as there is a strong likelihood that there have been long-term structural decreases in the need for industrial gas usage over the last decade.

Exhibit 9: Historical Natural Gas Consumption by Sector (Bcf/mo)



Source: Pace Global, EIA

Major long-term uncertainties on the demand side include the power sector response to new environmental regulations, including potentially mandatory carbon emissions limits and whether industrial gas demand will recover and grow or stagnate and decline. Another key factor is the economic displacement of coal by natural gas in response to low gas prices. Natural gas consumption in the power sector increased by 20.6 percent in 2012, on a year-over-year basis, but was stymied in 2013 as natural gas prices rose, reducing power generation demand for gas by 10%. In the power generation sector, a rapid implementation schedule for achieving interim targets for carbon emissions reductions could further induce a "dash to gas" and an exodus from older coal-fired plants, leading to a rapid increase in gas demand. A massive investment in wind power would make gas-fired generation the most practical source of standby and supplemental power as wind speeds and electricity load vary.

Exhibit 10 displays Pace Global's expected case price projections for natural gas at the Henry Hub as well as gas delivered to the relevant areas. The forecast is based on two years of recent market forwards blended with Pace Global's fundamental longer term view of market prices. With gas supply robust across the country and growing production volumes in the Marcellus shale play, supplies from the Rockies, Canada and even the Gulf Coast that have typically served the Northeast are now available to Midcontinent markets. Pace Global believes that production growth coupled with numerous pipelines from Canada, the Gulf Coast and the Rockies will keep the Midcontinent and Northeast regions well-supplied and basis values low. In particular, flows on the Rockies Express pipeline, which links Rockies gas with Northeast markets, are indicating that the gas is not reaching the Northeast (partially due to increased Marcellus production), but is instead being offloaded in Midcontinent markets.

Regional Gas Prices

Pace Global's regional gas price forecasting methodology incorporates regional supply basins, demand locations, and relevant pipeline infrastructure in order to project unique delivered gas prices across the entire PJM footprint.

TETCO M-3

The most relevant liquid Hub for the DPL zone is TETCO M3. In 2013, over 24,000 trades (nearly 130,000,000 MMbtu worth of gas) were made, making TETCO M-3 the 7th most active trading point. TETCO M-3 is a benchmark for gas pricing in the region north of Baltimore up to the outskirts of New York City, and frequently trades on top of the nearby Transco Zone 6 non-NY hub (which only saw 12,000 trades in 2013 for 66,000,000 MMBtu of gas). Because of the significant transmission flows from PJM-West to the more densely populated eastern regions, TETCO M3 gas pricing is most often the price at which the marginal resource is priced, which tends to drive up energy prices in the region.

TETCO M-3 is trading by as much as -1.00 below Henry Hub in the summer time due to the significant level of Marcellus production flowing into the region. However, summer prices are expected to rise to parity with Henry Hub by 2018 as demand rises and as Marcellus production is diverted elsewhere with the completion of new Market-to-Gulf Coast pipeline projects, such as those enumerated above. In the winter months, transmission capacity constraints continue to dominate during peak demand times. Winter price spiking is expected to continue for the foreseeable future, albeit attenuating down from +4.00 in January 2015 to +1.68 in January 2020. Overall, TETCO M-3 basis is trending downward, reaching negative values by the end of the Study Period.

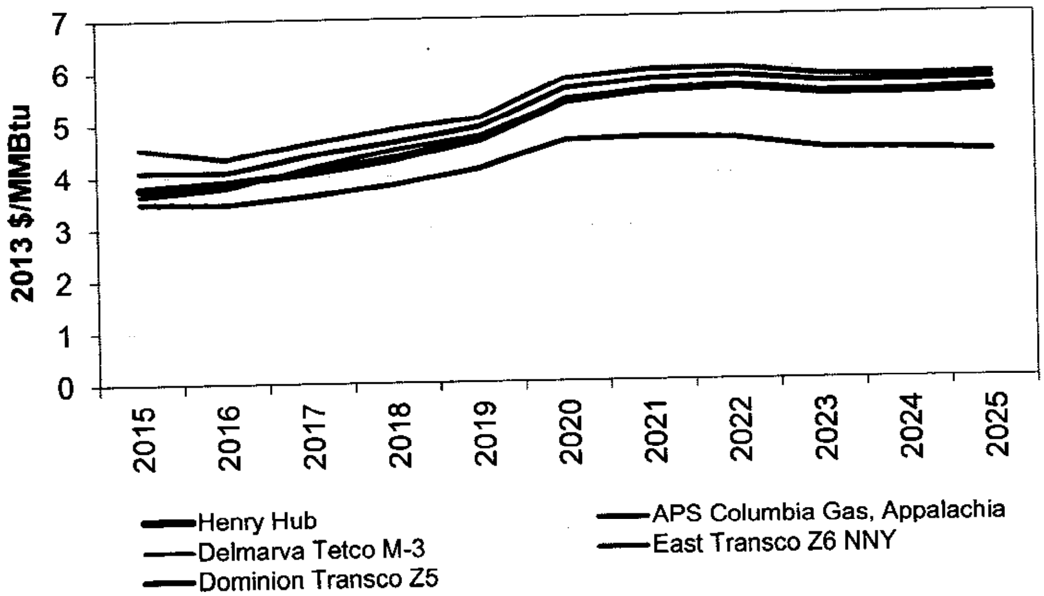
Exhibit 10 and Exhibit 11 summarize the reference case natural gas prices for the Henry Hub and associated regional basis points. Exhibit 10 shows the basis for several key points within PJM, while Exhibit 11 graphs the delivered prices for a selection of major hubs.

Exhibit 10: Natural Gas Price Basis Projections – Reference Case ($/MMBtu)

Year	Henry Hub	AEP	APS	ComEd	Delmarva	East	ATSI	PENELEC	Dominion
		Lebanon	*Columbia Gas, Appalachia*	*Chicao Citygates*	*Tetco M-3*	*Transco Z6 NNY*	*Columbia Gas, Appalachia*	*Dominion South. Tetco M-3*	*Transco Z5*
	$/MMBtu	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*
2015	3.77	-0.30	-0.27	0.11	-0.13	0.76	-0.27	-0.59	0.33
2016	3.88	-0.43	-0.41	-0.01	-0.10	0.47	-0.41	-0.52	0.21
2017	4.08	-0.37	-0.46	-0.02	0.10	0.55	-0.46	-0.30	0.32
2018	4.33	-0.29	-0.50	0.03	0.16	0.57	-0.50	-0.33	0.31
2019	4.67	-0.21	-0.53	0.01	0.08	0.42	-0.53	-0.53	0.25
2020	5.39	-0.21	-0.75	-0.02	0.01	0.43	-0.75	-0.70	0.24
2021	5.57	-0.22	-0.88	-0.05	0.02	0.40	-0.88	-0.76	0.22
2022	5.63	-0.24	-0.98	-0.06	0.01	0.37	-0.98	-0.83	0.22
2023	5.50	-0.23	-1.05	-0.06	0.02	0.35	-1.05	-0.86	0.22
2024	5.49	-0.24	-1.08	-0.07	0.02	0.32	-1.08	-0.91	0.22
2025	5.53	-0.24	-1.17	-0.07	0.08	0.32	-1.17	-0.92	0.23

Source: Pace Global.

Exhibit 11: Reference Case Natural Gas Price Projections for Relevant Gas Hubs (2013$)

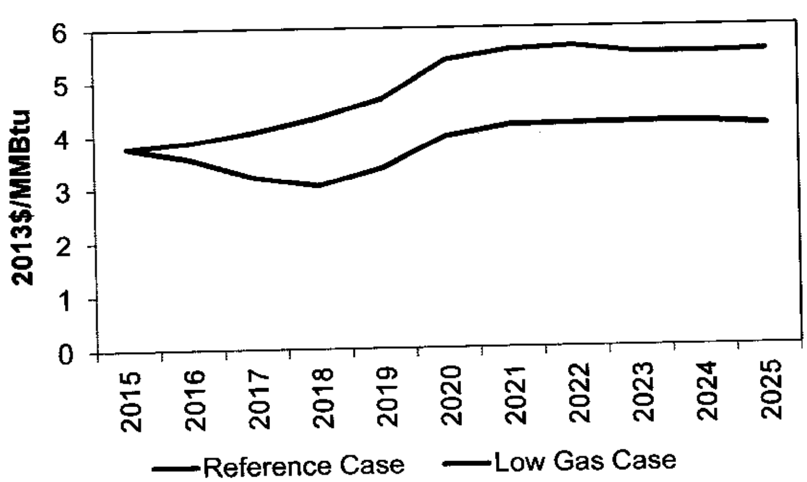


Source: Pace Global.

Natural Gas Price Uncertainty

In order to assess the impact of lower natural gas prices on the PJM power market, Pace Global developed a low natural gas price scenario that presumes more abundant domestic supply at lower production costs than those assessed in the reference case. Exhibit 12 summarizes the price projections for both the reference case and low gas case at the Henry Hub.

Exhibit 12: Henry Hub Reference Case and Low Gas Case Scenarios (2013$)



Source: Pace Global.

Generally, a low gas price case will stimulate a higher rate of demand from most sectors, particularly the price sensitive power generation sector and to a lesser extent the industrial sector. The low gas price case sees gas-fired power generation demand grow to 35.2 Bcf/d in 2020 and 42.8 Bcf/d in 2025 vs. 31.4 Bcf/d in 2020 and 34.5 Bcf/d in 2025 in the reference case. Industrial sector demand for natural gas also is higher, growing to 27.2 Bcf/d by 2025 in the low gas price case vs. 24.4 Bcf/d in the reference case, as industrial users (particularly from ethylene crackers, ammonia/urea/fertilizer plants, and gas-to-liquids plants) take advantage of the sustained low price environment and invest in long-term production facilities.

LNG demand is expected to be incrementally higher as a result of the low gas price environment, though not so much higher that the prices are materially affected. Liquefaction facilities will operate as baseload demand at an estimated 85 percent capacity factor. In a low gas price environment, this capacity factor may inch upwards to 90 percent. U.S. LNG demand in the low gas price case is expected to reach 8.0 Bcf/d by 2023 vs. 7.7 Bcf/d in the reference case. Facilities include: Sabine Pass, Cameron, Lake Charles, Freeport, Cove Point.

Given higher gas demand, both production and infrastructure build-out are assumed to be substantially higher in the low gas price case than in the reference case in order to keep downward pressure on prices. In terms of supply in the low gas price case, the price of WTI crude oil maintains in the $95/bbl range (versus the $85/bbl where current forwards are headed and where the reference case is set). As a result, the associated gas produced from oil-directed drilling as well as the revenue uplift from natural gas liquids helps buoy gas supply and keep a ceiling on gas prices. Drilling productivity is assumed to continue to grow robustly as producers gather more and more fracking data and adjust their drilling patterns to increase production while decreasing costs. Flaring is reduced in places like North Dakota, contributing the gas supplies.

Importantly, in the low gas price case, many of the proposed pipeline projects are completed (and more so than in the reference case), particularly the 12-15 Bcf/d of takeaway pipeline capacity currently proposed for the Marcellus and Utica region. The ability to move rapidly rising gas production in the Appalachian basin to premium markets in the Gulf Coast, the Southeast, and the Northeast help to keep downward pressure on prices in these regions and in the U.S. in general. Absent a high level of pipeline build-out, the U.S. will not benefit as efficiently and uniformly from the substantial lower gas prices seen at Dominion South Point and TCO Pool in the Marcellus/Utica regions.

COAL

Recent Trends in Coal Markets

U.S. coal demand in 2012 fell over 9 percent compared with the previous year. This drop in consumption was largely driven by low natural gas prices which have led to coal-to-gas switching in the power sector. Power sector coal consumption in 2012 decreased 11.5% compared to 2011. Pending environmental regulations associated with power plant emissions have the potential to make coal-fired generation uneconomical, particularly post-2015 with the onset of MATS regulations. Additional growth in coal's share of power generation is expected, reaching 44 percent in 2015.

Other drivers that will dictate future coal demand include renewable portfolio standards at the state and federal level and the possibility of environmental regulations around hydraulic fracturing. Consumption could decrease even more sharply if states choose to pursue aggressive renewable generation targets. However, legislation limiting hydraulic fracturing could reverse the current gas market oversupply with implications for higher coal demand.

National Coal Supply and Demand Assumptions

Demand-Side Drivers

Overcapacity in the coal industry throughout most of the 1990s resulted in low prices, which forced smaller producers to either exit the industry or be acquired by larger, financially stronger players. These low prices also resulted in the closure of many mines and limited investment in new productive capacity.

High natural gas prices between 2003 and 2008 caused the increased dispatch of coal-fired power plants. Between 2003 and 2005, coal consumption exceeded coal supply, resulting in a drawdown of inventories. However, U.S. coal production increased by approximately 27 million tons in 2006, allowing stocks to rebuild, and then declined slightly in 2007; production slightly exceeded demand in 2008. The 2009 global recession greatly depressed power demand and resulted in an 8.3 percent decline in coal production. Since then, production has grown by just shy of 1 percent annually in the wake of modest economic recovery. Emerging markets like China have led to increasing coal exports, which may continue to grow if domestic gas prices remain low. The recent low gas prices have slightly depressed coal production, which fell by 6.9 percent in 2012 compared to 2011.

The global economic downturn greatly depressed coal demand and prices, forcing many Appalachian producers to shut-in production. Additionally, gas prices have fallen to levels not seen since the 1990s. Gas prices continue to trade below their 10-year average. As long as gas prices remain low, coal demand will be negatively impacted. Some of the older, less efficient coal units are being supplanted by gas to meet base and intermediate load demand at current gas prices. Over the longer term, however, Pace Global expects that gas prices will rebound to prices in the $5-6 per MMBtu range on an annual basis. When this occurs, coal demand is projected to rise unless carbon regulations that place upward pressure on coal generation costs are passed. In the near term, coal's share of U.S. power generation is expected to grow from 37.4 percent in 2012 to 44% in 2015 as the gas market stabilizes.

On the industrial side, coal demand has declined in line with U.S.-based manufacturing. This decline has been seen with both steam coal (used for power and steam generation at plants) as well as metallurgical coal (used for steelmaking). Some industrial facilities have even converted to burn gas instead of coal for environmental reasons. In the long term, Pace Global expects industrial coal demand to decline at a similar rate to power sector coal demand.

Supply-Side Drivers

Pace Global expects future productivity increases in the western U.S., primarily in the PRB, and also in the Illinois Basin (ILB), to exceed those in traditional eastern mining areas. Productive PRB and ILB mines are expected to contribute to overall productivity gains for U.S. mining, albeit at a lower rate than gains experienced throughout the 1990s, as reserves in Central Appalachia either deplete or become more difficult to access. These overall productivity gains are likely to prevent major supply shortages and increased production costs associated with the gradual decline of Central Appalachian production. However, as discussed below, there are several environmental and safety issues for eastern mines that may put upward pressure on mining costs.

Coal productivity gains east of the Mississippi will be dampened by a number of recent EPA actions relating to mountaintop mining and stream conductivity. In June of 2009 the Obama administration along with the EPA, the Department of the Interior and the Army Corps of Engineers, announced that it would take a much stronger stance in reviewing the environmental impacts of mountaintop mining in the six eastern mining states of Kentucky, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia, which covers Central and Northern Appalachia and a small part of the Illinois Basin. Since then, the EPA has increased scrutiny of permits for the discharge of fill material needed under the Clean Water Act (CWA) Section 404, which directly affects surface mining operations in those states. The EPA selected 79 permits for additional review through a process called the Enhanced Coordination Procedures (ECP), and even revoked the permit of a large surface mine through its rarely used veto power. As a result of this and other factors, the issuance of new CWA Section 404 permits since the 2009 announcement has slowed to a trickle.

In April of 2010, the EPA issued its first water conductivity standards for the coal industry that must be met to obtain National Pollutant Discharge Elimination System (NPDES) permits in the eastern mining states. The new benchmark standards went into effect immediately after its announcement and are needed for new mining permits and permit renewals for the discharge of water from mine sites in the six eastern mining states mentioned above. As a result, new surface mining permits and permits for deep mines with significant water discharge needs will be very difficult to obtain in the next several years. The Central Appalachia area is likely to be affected the most by the new benchmark as surface mines make up nearly half of all operations in the basin.

Though the effects of this more stringent oversight of eastern coal mining on supply may be felt minimally over the next few years as current permits are likely to meet demand for eastern coal, Pace Global believes that significant impacts will be felt as early as 2014 if current regulations stay in place. Starting in 2014, Central Appalachian production could be reduced by tens of millions short tons per year as existing mines are depleted and new permitting becomes more difficult. The result would be an acceleration of the move towards alternative coals in the Illinois Basin and Powder River Basin and a potentially greater reliance on natural-gas-fired generation in the U.S.

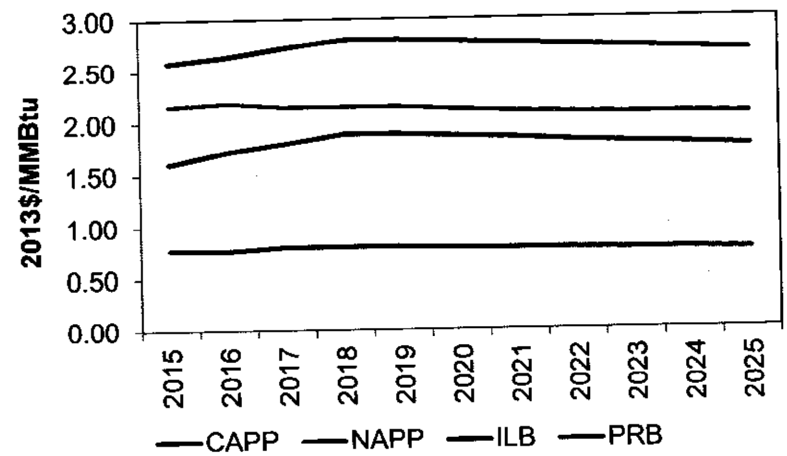
Liquidity

The domestic coal market is considerably less liquid than the natural gas, oil, or oil products markets. Historically, electricity generators have purchased approximately 80-90% of their coal under contracts lasting one year or more in order to ensure security of supply. While it is likely that utilities will continue to use the spot coal market, Pace Global expects electricity generators to continue to opt for a significant proportion of term contracts, one to five years in duration, in order to reliably supply their plant portfolios. Coal contract terms have shortened in recent years; however, as coal producers positioned themselves to capture more of the upside in coal market prices. Therefore, based on Pace Global's recent experiences in the market, most new term contracts are likely to be for three years or less.

Coal Market Prices

Pace Global assesses basin-level market fundamentals and develops projections based on current market forward signals and expected market trends. In the near term, Pace Global expects CAPP, ILB and PRB prices to see slight gains associated with increased power sector demand as well as decreasing labor productivity over the next five years while NAPP prices are expected to remain fairly flat. Over the longer term (2020-2030), all basin prices are expected to decline in the face of a significant demand decrease associated with environmental regulations.

Exhibit 13: Reference Case Coal Prices for Four Basins (2013$)



Source: Pace Global.